2003 ANNUAL REPORT

COMPTON
PETROLEUM CORPORATION

PEOPLE + OPPORTUNITY + CAPITAL = SUSTAINABLE GROWTH + LONG-TERM VALUE

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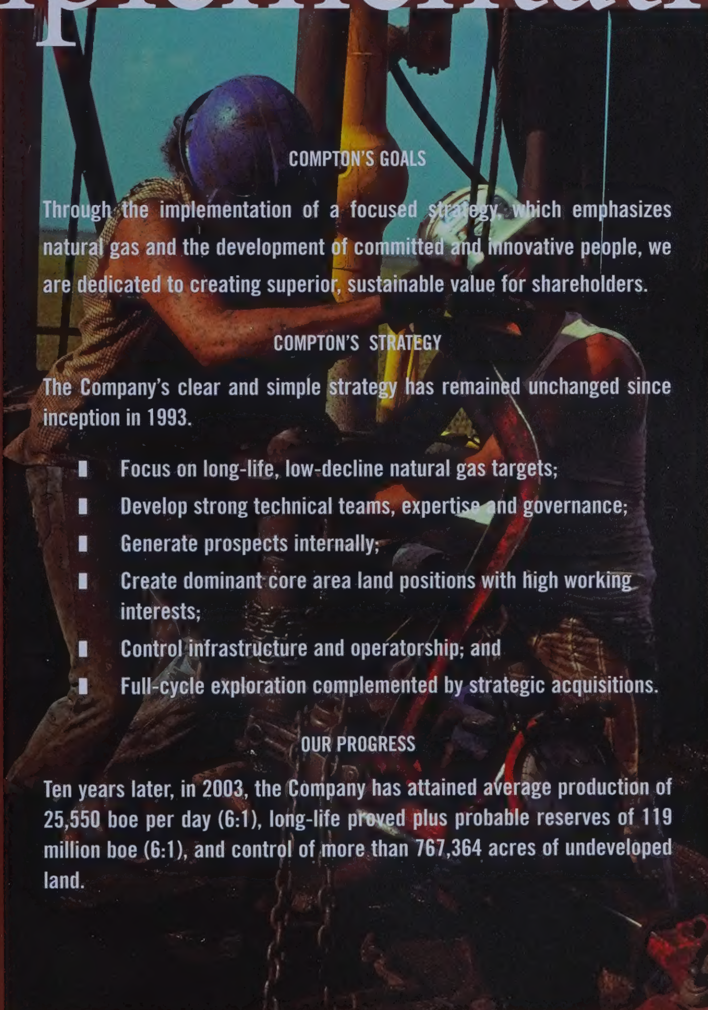
ANNUAL MEETING

The Annual General Meeting of Shareholders will be held on Thursday, June 17, 2004 at 4:00 p.m. in the Devonian Room, Calgary Petroleum Club, 319 - 5th Avenue S.W., Calgary, Alberta, Canada.

SOME HISTORY

Compton Petroleum Corporation is a Calgary based independent public company actively engaged in the exploration, development and production of natural gas, natural gas liquids and crude oil in the Western Canada Sedimentary Basin. The Company's capital stock trades on the Toronto Stock Exchange (TSX) under the symbol CMT, and is included in both the S&P/TSX Composite Index and the TSX Mid-Cap Index.

A clear Model *and resolute* Implementation



COMPTON'S GOALS

Through the implementation of a focused strategy, which emphasizes natural gas and the development of committed and innovative people, we are dedicated to creating superior, sustainable value for shareholders.

COMPTON'S STRATEGY

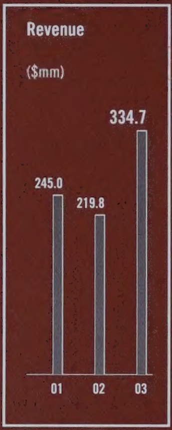
The Company's clear and simple strategy has remained unchanged since inception in 1993.

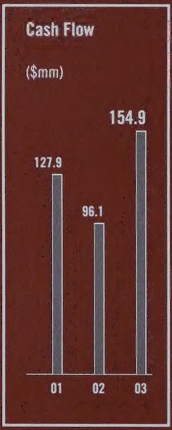
- Focus on long-life, low-decline natural gas targets;
- Develop strong technical teams, expertise and governance;
- Generate prospects internally;
- Create dominant core area land positions with high working interests;
- Control infrastructure and operatorship; and
- Full-cycle exploration complemented by strategic acquisitions.

OUR PROGRESS

Ten years later, in 2003, the Company has attained average production of 25,550 boe per day (6:1), long-life proved plus probable reserves of 119 million boe (6:1), and control of more than 767,364 acres of undeveloped land.

Financial Results





FINANCIAL

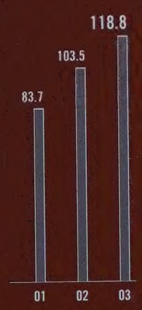
($000s, except where noted)		2003	2002	2001
Total revenue		**$ 334,693**	$ 219,787	$ 244,970
Cash flow from operations [1]		**$ 154,893**	$ 96,072	$ 127,861
Per share:	Basic *($)*	**$ 1.33**	$ 0.85	$ 1.16
	Diluted *($)*	**$ 1.27**	$ 0.81	$ 1.11
Net earnings		**$ 118,880**	$ 18,312	$ 55,015
Per share:	Basic *($)*	**$ 1.02**	$ 0.16	$ 0.50
	Diluted *($)*	**$ 0.97**	$ 0.16	$ 0.48
Capital expenditures		**$ 285,483**	$ 155,108	$ 190,467
Corporate debt, net		**$ 353,402**	$ 268,495	$ 207,850
Shareholders' equity		**$ 356,906**	$ 240,118	$ 212,665
Share Price:				
High		**$ 6.35**	$ 5.35	$ 6.19
Low		**$ 4.40**	$ 3.20	$ 2.60
Close		**$ 6.00**	$ 5.09	$ 4.20
Average daily trading volume		**686,100**	324,865	319,545

(1) *Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital.*

Operating
Results

Daily Production
(mboe/day)

Proved plus Probable Reserves
(mmboe)

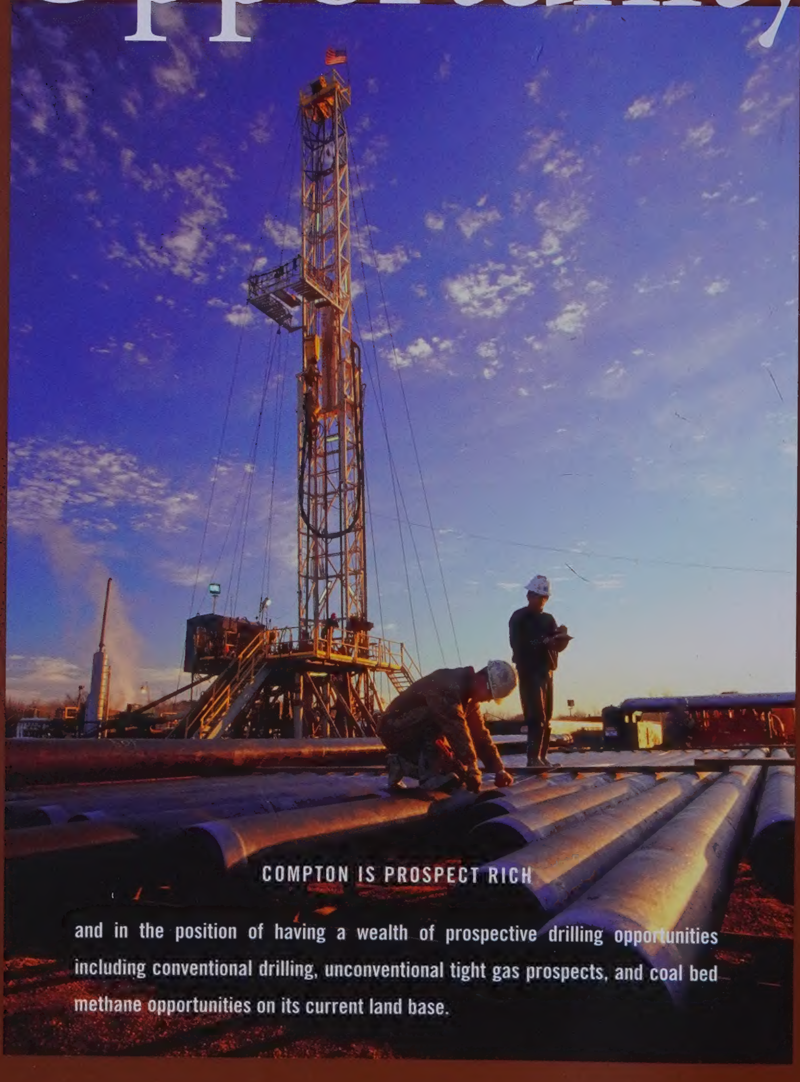


OPERATING

(units as noted)	2003	2002	2001
Average daily production volumes:			
Natural gas *(mmcf/d)*	**118**	112	101
Liquids (light oil & ngls) *(bbls/d)*	**5,924**	6,503	6,546
Total oil equivalent *(boe/d)*	**25,552**	25,137	23,404
Average pricing:			
Natural gas *(per mcf)*	**$ 6.01**	$ 3.67	$ 4.77
Liquids *($/bbl)*	**$ 34.39**	$ 29.43	$ 28.83
Total oil equivalent *($/boe)*	**$ 35.66**	$ 23.95	$ 28.68
Field operating netback *($/boe)*	**$ 21.17**	$ 13.82	$ 17.42
Cash flow netback *($/boe)*	**$ 16.49**	$ 10.39	$ 14.98
Undeveloped land:			
Gross acres	**1,042,802**	1,042,923	962,259
Net acres	**767,364**	742,465	700,695
Average working interest	**74%**	71%	73%
Reserves:			
Proved *(mboe)*	**84,627**	82,156	71,754
Proved plus probable (1) *(mboe)*	**118,763**	103,501	83,675

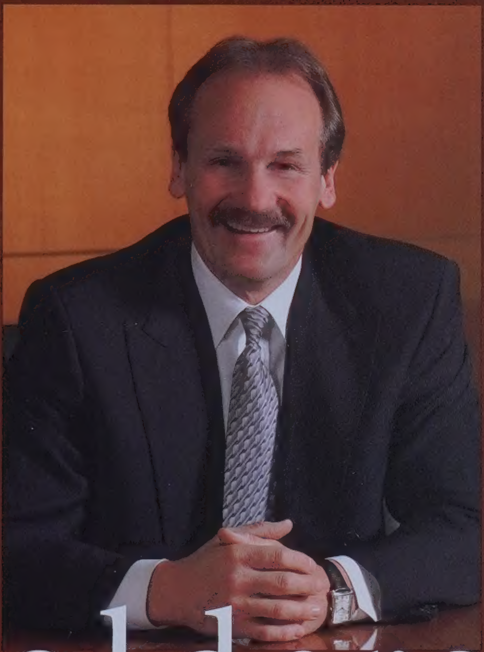
(1) Represents proved plus risked probable reserves (established) for 2002 and 2001.

Abundant Opportunity



COMPTON IS PROSPECT RICH

and in the position of having a wealth of prospective drilling opportunities including conventional drilling, unconventional tight gas prospects, and coal bed methane opportunities on its current land base.



To our Shareholders

The outlook for Compton Petroleum and the oil and gas industry continues to be positive. Compton's 2003 activities have strengthened our core asset base and added further upside to the Company. Significant progress occurred on several strategic developments including Compton's 2003 priority to eliminate processing and pipeline capacity constraints.

HIGHLIGHTS

- Record cash flow from operations of $155 million
- Independent reserve report evaluated reserves at over $1 billion at 8% DCF
- 118 million boe proved plus probable reserves
- 80% of Compton's reserves are long life tight natural gas reserves
- Reserve replacement of 2½ times production
- Control of the Mazeppa gas plant and facilities in June 2003
- Expansion of Mazeppa commenced December 2003, completed May 2004

DRILLING SUCCESS AND RESERVES

The growth of Compton's reserve base and value to its shareholders has been the result of applying a consistent strategy to our drilling programs. We have developed a strong technical expertise in complex tight gas reservoirs with approximately 80% of Compton's reserves at December 31, 2003 comprised of tight gas. While the potential of unconventional tight gas has only recently become recognized in Canada, it has become a very significant source of production in the United States. Recent major North American acquisitions, such as Encana's strategic $2.7 US billion acquisition of Tom Brown, Inc. illustrates the future importance and value of tight gas to the oil and gas industry. Compton's large undeveloped land base will continue to generate years of reserve growth and opportunities from tight gas reservoirs.

Compton has developed expertise in the discovery and development of unconventional basin-centred gas resources. These regionally extensive gas systems are classified as unconventional since the reservoirs are essentially water free, abnormally pressured and generally have lower permeability. Such systems experience relatively high decline rates during initial production but stabilize at very low decline rates, resulting in long life reserves. These massive gas accumulations are one of the few remaining economically important gas exploration targets in North America. With its success in the Hooker and Niton properties, Compton has established itself as a leader in the exploration and development of this significant resource base.

Compton's reserve reports have always been stable and consistent with no major revisions. Due to the increasing proportion of the Company's tight gas reserves and large future capital commitments to tight gas, Compton determined it was imperative to engage an internationally recognized Tier 1 independent reserve evaluator with extensive experience and expertise in tight gas reserve determinations. Compton's decision to engage Netherland Sewell & Associates, Inc. ensured that the Company's tight gas reserves would be evaluated in compliance with National Instrument 51-101, and in a manner consistent with other E&P companies with comparable reserves. Compton's 2003 reserve report contains a thorough review of all our reserves, and while conservative due to our large inventory of newly drilled wells receiving limited reserves due to short production history, the report maintains the consistent historical pattern of increased reserves year over year.

Compton had a successful drilling program in 2003, drilling 168 wells at approximately an 83% success rate. The Company accelerated its drilling activity in the fourth quarter of the year, after unseasonably wet spring weather and a lengthy breakup period slowed earlier activities. The 2003 drilling program added 3 million boe of proved reserves after production and 15 million boe of proved plus probable reserves, replacing production by two and a half times. The Company's finding, development and acquisition costs ("FD&A") for proved plus probable reserves was $14.11 per boe.

CONSTRAINED PRODUCTION AND EXPANDED FACILITIES

Production volumes in 2003 were constrained by weather, late year drilling and gas plant and pipeline capacity restrictions due to the previous gas plant owner's failure to expand the Mazeppa and Gladys facilities. Compton's 2003 average production was 25,550 boe/d with over 80 wells waiting to be tied in at year end.

The elimination of constraints was a top priority for Compton and was resolved through several steps. Compton acquired control of the Mazeppa and Gladys facilities and related infrastructure through the purchase by Mazeppa Processing Partnership in June, 2003. This allowed Compton as operator to commence engineering for the expansion of processing and infrastructure facilities in Southern Alberta and to apply for AEUB approval, which was received in December.

Shortly after the Mazeppa acquisition, the plant was shut down for three weeks in September for routine turnaround maintenance, which is conducted every three to four years. During the turnaround, Compton was able to take advantage of the downtime to conduct preparatory work on the plant for its major expansion. While the loss of production for approximately three weeks was significant, the early maintenance ensured that the facilities would continue to operate efficiently and safely.

After the Mazeppa and Gladys facilities acquisition, Compton worked to expand the Mazeppa plant and the Southern Alberta gathering and pipeline systems. Sour gas processing capacity at the Mazeppa gas plant was expanded from 80 mmcf/d to 90 mmcf/d and a 45 mmcf/d sweet gas addition was completed in May 2004. Total processing capacity in Southern Alberta, commencing the second half of 2004, will be 172 mmcf/d. The pipeline system was expanded in 2003 with the additional offloading of gas production from Brant to the ATCO sales pipeline and the debottlenecking of the Hooker pipeline system. The Hooker pipeline system now has a capacity of 80 mmcf/d. After the expansion and debottlenecking, Compton will have added adequate processing capacity for the next few years, and any future expansions will be completed by Compton as operator, ensuring a quick response and planning time.

Compton spent approximately $110 million on plant and facilities, representing approximately 40% of total 2003 capital expenditures, a significant commitment to future growth.

INDUSTRY

Cold winter weather and increased demand depleted natural gas storage levels in the first quarter of 2003. However, strong injections returned North American storage to historical levels by the end of the year. With the recovery of storage levels, natural gas prices stabilized in the US$5.00 - $5.50/mcf NYMEX range throughout the remainder of 2003. Although the industry entered 2004 with adequate natural gas supplies, we believe demand will continue to rise reflecting increased electricity generation. We expect natural gas prices to average Cdn $5.00 - $5.50/mcf in 2004. However, it appears oil prices will continue to be volatile in 2004 due to increased world demand and supply uncertainty in a number of producing countries.

While the demand for natural gas continues to grow in North America, production may be peaking. Natural gas wells in the Western Canadian Basin continued a 10 year trend of lower initial production rates and higher first year decline rates, resulting in an overall increase of decline rates in the Basin. In order to maintain current production levels, producers must increase drilling and pursue unconventional sources of natural gas. This was illustrated in 2003 with a record number of wells drilled in Canada, while overall gas deliverability remained flat with 2002.

Unconventional sources of natural gas are necessary to offset conventional gas declines and provide the production growth necessary to fulfill increasing demand. Unconventional sources include coalbed methane, shale gas, liquefied natural gas and tight gas. Tight gas, which comprises 80% of Compton's reserves, is expected to be the largest unconventional form of natural gas production in the near future. The Canadian oil and gas industry is also aggressively pursuing coal bed methane potential and the early results show significant upside. These new resource plays require a large upfront land base, technical expertise, experience and have difficult project economics, which puts more pressure on the industry.

Drilling rigs, service rigs, equipment and experienced crews are currently operating at maximum capacity, which has resulted in escalating drilling and operating costs. Strong demand for experienced professionals has contributed to inefficiency in the industry. Prospective land prices continue to spiral upwards and are consuming an increasing portion of annual budgets and adding considerably to FD&A costs. Deeper drilling and more complex plays will also contribute to higher FD&A costs for the industry. Additionally, the increasing complexity and ever changing regulations regarding license applications, environmental and governance matters is adding significantly to overall costs, workloads and timing of operations. The end result is that while commodity prices are strong, the cost, effort and time of doing business have also risen dramatically.

2004 OUTLOOK

The oil and gas industry is facing a particularly challenging year in 2004 with many continually changing variables. Commodity price volatility, cost escalation, the potential for further strengthening of the Canadian dollar, combined with a shortage of service equipment and skilled technical and professional labor will present difficulties. Compton is prepared to quickly adjust to changes as they occur.

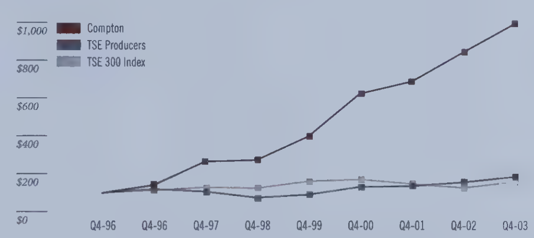
Compton's challenge for the next year is one of balancing the need to achieve desired growth and fiscal responsibility. The Company is in the enviable position of having a wealth of prospective drilling opportunities including conventional drilling, unconventional tight gas prospects, and coal bed methane opportunities on its current land base. With respect to coal bed methane, Compton's lands contain several coal bed methane formations (which are mostly water free) uphole of Compton's existing deeper producing reservoirs. Compton has completed a resource study in Southern Alberta and is now testing several wells which, if successful, would lead to an exploration program. Significant capital is required to realize on these opportunities and care must be taken to be fiscally and environmentally responsible. Compton is in the process of financing the Mazeppa and Gladys facilities acquisition (expected to close in May 2004) thereby returning $75 million to Compton. The Company plans to drill 190 wells and we are comfortable that Compton's financial and staffing capabilities can successfully accomplish our 2004 operations within budgeted cash flow.

Supplementing internal growth with strategic acquisitions is a major component of Compton's long term strategy. The Company considered several acquisition opportunities in 2003, however, they did not compliment Compton's overall plans. Compton will continue to evaluate acquisitions opportunities, as exemplified by the Redwood Energy, Ltd. acquisition early in 2004. If financing is required to complete an acquisition Compton has numerous alternatives, including an equity issue, bank debt and public debt markets.

Compton has experienced success and created significant value with its current strategy and does not plan to deviate significantly from it. With years of internal drilling opportunities on the Company's lands, the greatest value for shareholders will be generated by proving up core areas and increasing production, reserves and value. Compton's Board of Directors has approved a strategic plan for the Company and is active in continually monitoring and evaluating the Company's opportunities in order to maximize shareholder value. The Board will continue to provide strategic direction and advice.

In summary, Compton has just completed a year in which it has achieved major accomplishments. We engaged a Tier 1 reserve evaluator, increased proved plus probable reserves by 15% and complied with the rigorous new requirements of National Instrument 51-101. We acquired control of the world class Mazeppa gas plant, commenced expansion and debottlenecking of our infrastructure systems in Southern Alberta, drilled 168 wells and increased our large land base. Our stock price closed the year at $6.00, up 18% from the prior year. We have finished an all out effort to expand Compton's facilities with the expansion of Mazeppa and its systems. The second half of 2004 will see the fruition of our hard work with a return to growth in production. We are confident in our current direction, accomplishments and future opportunities. When our shareholders consider Compton's long life gas reserves, solid reserve report, stable production and an ambitious drilling program on our large land base, it is evident the future has many opportunities.

Our stock price closed the 2003 year at $6.00, up 18% over 2002.



CONCLUSION

Compton is a vibrant, growing company. Strategic and internal opportunities driven by talented and dedicated employees will continue to generate significant value, which will become increasingly apparent over the next few years.

2003 has been a busy year for Compton and it is important to recognize those who make the Company's long term strategy a reality. I would like to thank Compton's employees and management team. The dedication, drive and enthusiasm displayed every day by our staff is contagious and is the driving force that ensures Compton's success. I would also like to thank Compton's Board of Directors for another year of outstanding guidance.

Sincerely,

Ernie Sapieha
President & Chief Executive Officer

Executing our strategy is a

Team Endeavour

The dedication, drive and enthusiasm displayed every day by our people is contagious and the driving force that ensures Compton's success.


KIM DAVIES


ROB DION


GARY FOLLENSBEE


MARC JUNGHANS


CORINNA KING


NORM KNECHT


THERESA KOSEK


BILL LEONARD

and enterprise strength has much to do with strong

Leadership


DEREK LONGFIELD


GARRY MCCULLOUGH


TIM MILLAR


WADE MROCHUK


PAUL PARZEN


GREG SHYPTKOVSKY


MURRAY STODALKA

We are

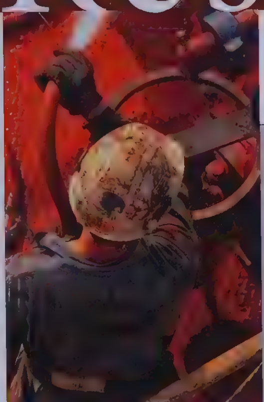
Asset Rich

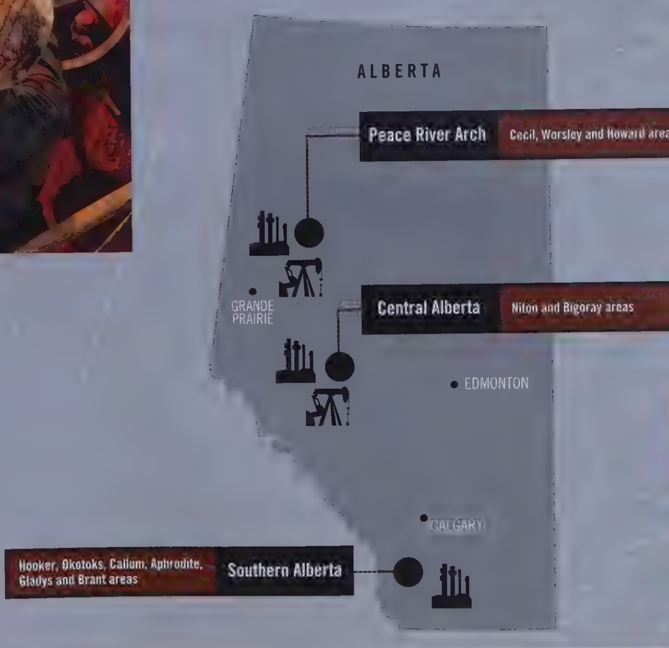
COMPTON IS ASSET RICH

Our core areas provide us with a variety of assets and prospects and a balanced risk profile — from long-term exploration and development gas prospects in Southern and Central Alberta to mature, light oil exploitation projects in Central Alberta and the Peace River Arch.

Compton focuses on three core areas within the Western Canadian Sedimentary Basin in Alberta, Canada. These areas provide the Company with a variety of assets and prospects, from long-term exploration and development gas prospects in Southern and Central Alberta to mature, light oil exploitation in Central Alberta and the Peace River Arch. This ensures a balanced risk profile. Compton's properties continue to reflect the Company's focus on natural gas, which accounted for approximately 80% of the Company's production in 2003.

A wealth of Resources





Compton has gained considerable technical expertise and achieved significant success in exploring for and developing tight, low-decline natural gas reservoirs. This experience is transferable, giving the Company exploration and operating efficiencies in multi-zone tight gas areas such as Hooker, Niton, Gladys, Centron, Brant, Callum and Okotoks. At December 31, 2003, tight gas properties comprised 80% of Compton's proved plus probable gas reserves.

The Company strives to operate the majority of its properties and maintain a high working interest in undeveloped lands. This ensures control of the timing of capital expenditures and ensures efficient exploration and development activities. On December 31, 2003, Compton operated approximately 75% of its production base and had an average working interest of 74% in its undeveloped acreage.

Compton believes that control over gathering and processing infrastructure is critical to the success of its full-cycle exploration and exploitation programs, and currently owns or has access to critical infrastructure in each of its three primary producing areas. The Company faced production constraints in 2003 due to limited processing and pipeline capacity in Southern Alberta. Several initiatives were undertaken by the Company to expand facilities and the constraints have been eliminated.

Compton has assembled a substantial portfolio of undeveloped land its core areas, totalling 1,042,802 (767,364 net) acres at December 31, 2003. It is Compton's intention to develop its natural gas and crude oil reserves primarily through internal prospect generation and the Company believes its current land base is sufficient to produce over five years of internally generated exploration and development programs.

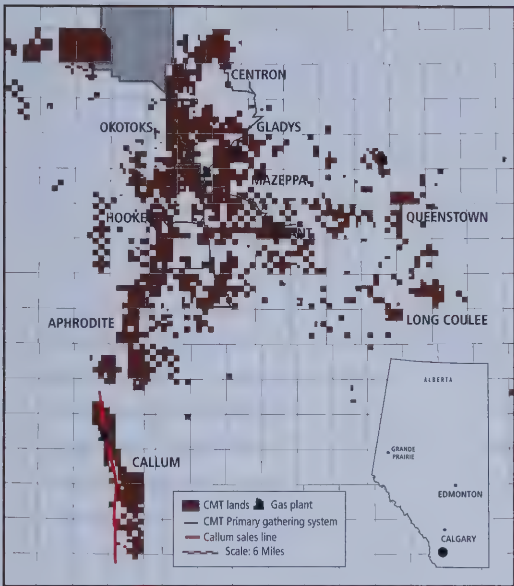
PROPERTY SUMMARY

	Southern Alberta	Central Alberta	Peace River Arch	Other	Total
Developed and undeveloped land *(gross acres)*	724,492	487,331	208,160	181,433	1,601,416
Undeveloped land *(gross acres)*	480,859	284,696	136,713	140,534	1,042,802
Average operating interest	85%	60%	70%	60%	75%
2003 annual average production *(boe/d)*	14,972	4,820	4,550	1,210	25,552
2003 capital expenditures *($millions)*	$127	$39	$31	$24	$221
2003 wells drilled *(gross)*	102	36	30	–	168
2003 success rate	87%	86%	66%	–	83%
2003 proved plus probable reserves *(mboe)*	82,203	18,823	15,144	2,593	118,763

SOUTHERN ALBERTA

Southern Alberta is Compton's largest core area, prospective for multi-zone natural gas, including medium depth Belly River, deep tight Basal Quartz and Wabamun Crossfield gas. Additional exploration upside exists in the Edmonton, Viking and Glauconite zones, as well as the coal bed methane play that lies immediately north of Compton's Southern Alberta land base. An undeveloped land base of 480,859 (399,736 net) acres will provide years of internal drilling opportunities.

Compton drilled 102 (91 net) wells in Southern Alberta in 2003 with an 87% success rate. In 2004, Southern Alberta will again be the primary focus of the Company, with plans to drill 112 (99 net) locations with a capital expenditure budget of $137 million in the area.



Hooker

The Hooker play targets tight Basal Quartz sandstones at depths ranging from 2,400 to 3,400 metres. Hooker also holds up hole potential in multiple Belly River sands. The play covers an extensive area of over 150 sections, at working interests ranging from 50-100%. Current production extends over four townships. The Hooker trend has the potential to grow to nine townships with a resource potential of 500 bcf of gas reserves net to Compton.

In 2003, Compton focused on continuing to expand the Hooker play into predominantly 100% owned acreage. The Company drilled a total of eight exploratory and 11 development wells with a success rate of 74%. The exploration program extended the trend six miles to the north and three miles to the southeast and continued to provide invaluable experience and understanding of these types of tight gas reservoirs.

With the extension of the Hooker pool to the north and southeast, Compton estimates that only half of the Hooker trend, as it exists on Compton's lands, has been developed to date. At the current drilling pace, over five years of future drilling locations exist at Hooker. In 2004, the Company expects to drill 24 wells in the Hooker trend.

Aphrodite

Aphrodite is a geologically analogous extension to the Hooker Basal Quartz trend. Compton drilled and cased two exploratory wells at Aphrodite in 2003. Continued exploration activities are ongoing.

Centron/Gladys/Brant

Located northeast of Hooker, the Centron/Gladys/Brant area offers medium depth gas in stacked, Belly River sandstones averaging 1,200 meters in depth. In addition to Belly River production, deeper exploration opportunities are present in the area. Compton's Belly River production currently extends from Hooker to Centron, over an area of 28 townships with very few down spacing locations drilled to date. On lands adjacent to Compton's acreage, historically more than one well per section has been required to adequately drain the Belly River zone.

An unusually wet spring in 2003 created drilling delays, but Compton aggressively pursued its medium depth gas program in the second half of the year. Using seismic data and trend mapping, the Company drilled a total of 70 wells with an 89% success rate. This program resulted in the discovery of new pools six miles south and five miles east of the existing Belly River producing area. In 2004, Compton will continue its extensive drilling program in the area with 74 wells planned. Additionally, the Company plans to assess coal bed methane opportunities at Centron.

Okotoks/Mazeppa

The Okotoks field has historically been associated with the Okotoks Wabamun "B" pool, a one TCF, deep, tight sour gas pool. Since acquiring producing assets in the area in 1996, Compton has continued to expand its operations, and has developed the property into a multi-zone exploration and exploitation play, with potential for production throughout a 5,000 foot vertical section. Production from the Wabamun formation commenced nearly 50 years ago, and the remaining reserves from this zone will support production from existing producing wells for at least another 50 years.

The Wabamun pool provides numerous opportunities to increase and accelerate reserve recovery of the sour gas reserves through the use of extended-reach horizontal wells from single surface locations, as well as from existing vertical wellbores. This depletion method minimizes the impact of activity on surface development. Most notable in this type of exploitation plan is Compton's application for approval to drill up to six horizontal wells at the north end of the Okotoks Wabamun "B" pool, just outside the southeastern limits of the City of Calgary. This unique, cooperative project is designed to manage and coordinate subsurface development with surface development, where existing sour gas operations are faced with encroachment of urban communities. The well license applications are currently before the Alberta Energy and Utilities Board, and, if approved, Compton has committed to abandon all sour gas wells in the Okotoks area within 15 years, compared to the projected remaining life of more than 50 years for the two existing wells.

In addition to the Wabamun zone, Compton currently produces from several other uphole formations in the area, including the Mississippian, Basal Quartz and Belly River zones. With an extensive and expanding infrastructure in place, Compton has the advantage of being able to exploit these shallower zones at low finding and development costs.

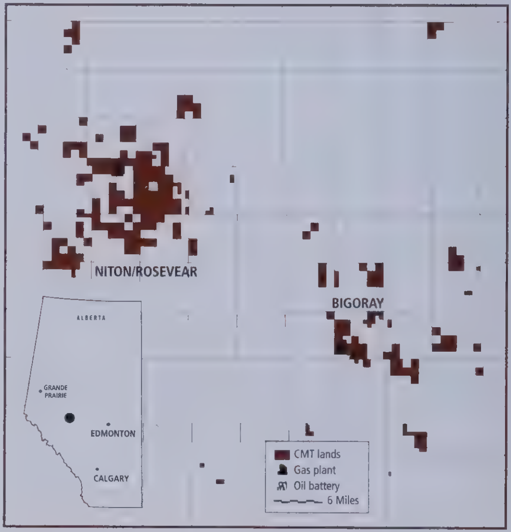
Callum

Callum is the Company's most southern area of operations with wells averaging 2,800 metres in depth. The play is prospective for thrusted multiple Upper Cretaceous Belly River sands. In 2003, Compton drilled three wells with a 100% success rate. The Company holds over 100 sections of undeveloped land at Callum and plans to continue exploring the Callum area with five wells planned in 2004.

CENTRAL ALBERTA

Central Alberta provides Compton with excellent exploration and development drilling opportunities and allows the Company to adopt an approach similar to its successful deep basin style Southern Alberta developments. Compton holds 284,696 (181,801 net) acres of undeveloped land, located approximately 100 km west of Edmonton.

Drilling in Central Alberta was delayed in the first half of the year due to wet spring weather. However, by year end the Company had drilled 36 (21 net) wells with an overall success rate of 86%. In 2004, Compton plans to spend $33 million in capital expenditures, drilling 35 (32 net) wells in the area.



Niton

The Company entered the Niton area in December 2002 by acquiring 100 sections of undeveloped land, a 100% working interest in a 5 mmcf/d natural gas plant and production of 220 boe/d. Compton has expanded its land position throughout 2003 and held 148 net sections in the area at December 31, 2003. Wells in the Niton area average 2,600 metres in depth, with primary targets in the Gething and Rock Creek sands. Uphole opportunities are also present in the Bluesky, Viking and Cardium zones. The Niton area is very promising as its tight sandstones are geologically similar to the Hooker trend.

In 2003, 14 wells were drilled at Niton with a 93% success rate. Results were very promising, generating the identification of several new drilling locations. Compton also expanded its 100% owned gas plant to 10 mmcf/d capacity in December 2003. The Niton area is one of increasing focus for the Company and the exploration program will be expanded to 14 wells in 2004.

Thornbury

Shallow gas drilling at Thornbury targets the McMurray zone at an average depth of 400 metres. In the first quarter of 2003, Compton drilled three successful gas wells, two dry holes and one standing well and plans to drill 15 wells at Thornbury in 2004.

Bigoray

Bigoray is a mature, high quality, light oil producing area that provides cash flow for Compton to finance exploration in other areas. Production from the Cardium sandstone has been maintained throughout 2003 as a result of continued success of the waterflood project. In 2004, Compton will continue to focus on efficient exploitation of reserves in place and plans to re-initiate an exploration effort with three wells planned.

PEACE RIVER ARCH

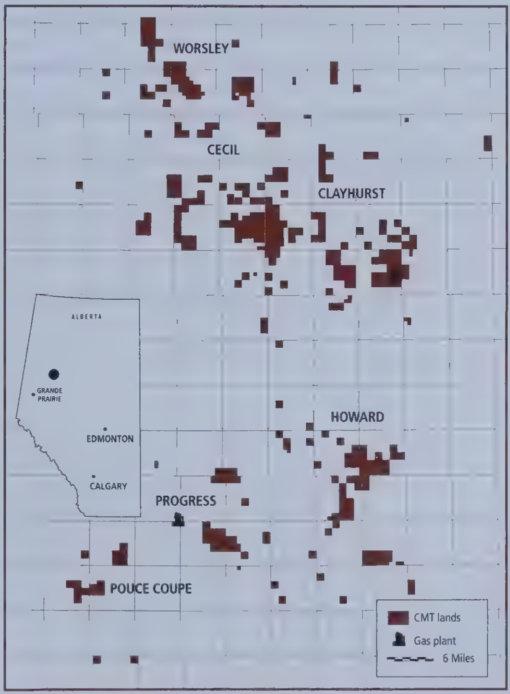
The Peace River Arch area, located north of Grand Prairie, contains multi-zone potential for both exploration and development opportunities. This core area includes both light oil production at Cecil/Worsley and natural gas exploration at Clayhurst, Howard and Pouce Coupe. The Company holds 136,713 (93,608 net) acres of undeveloped land in the area.

In 2003, Compton drilled 30 (22 net) wells in the Peace River Arch with a 66% success rate. The Company plans to drill 28 (20 net) locations in 2004 with a capital expenditures budget of $20 million.

Cecil/Worsley

Together, the Cecil and Worsley Charlie Lake pools are estimated to hold 187 million barrels of oil-in-place with an expected primary recovery of 5% to 7%. Waterflooding has the potential to double oil recovery from the Charlie Lake reservoirs. A pilot waterflood in the centre of the Worsley Charlie Lake pool commenced in June 2002 to optimize oil recovery. In December 2002, a response to the waterflood was evident in offsetting wells. The Worsley waterflood project has continued to show success in 2003 and a second pilot waterflood on the North end of the pool has been initiated. A field wide waterflood project is planned at Worsely in 2004.

The 2003 drilling program included 15 wells and extended the Worsely oil pool a half mile to the north with three successful step outs. As a result, 16 extension and infill wells are planned for Cecil/Worsley in 2004.



Howard

Compton holds over one township of prospective lands in the Howard area, with an average working interest of 80%. The primary target is gas in shallow Dunvegan sandstones at a depth of 450 meters. However, the area also has potential in the deeper Charlie Lake and Kiskatinaw zones. The Company drilled seven wells in 2003 and intends to drill seven follow up locations in 2004.

Production volumes in 2003 were constrained by gas plant and pipeline capacity restrictions due to the previous owner's failure to expand facilities. The removal of these constraints became a top priority for Compton in 2003, and was resolved through several steps, outlined below.


MAZEPPA GAS PLANT IN SOUTHERN ALBERTA

Timing	Event	Details
1997	Mazeppa Plant Acquired	Acquired a 94% interest in the Mazeppa gas plant with 40 mmcf/d capacity, 10 mmcf/d net sales, 20 mmcf/d production and 50 bcf reserves for $50 million.
	Mazeppa Plant Expanded	The Southern Alberta gas processing system was full. Mazeppa gas plant expanded from 40 mmcf/d to 80 mmcf/d capacity.
1998	Mazeppa Plant Sold	Mazeppa gas plant sold in 1998 for $82 million with favourable processing and drilling incentives, which eliminated Compton's debt, ensured low processing charges and provided additional capital for its drilling program through incentives. Compton retained production and reserves purchased with the plant in 1997.
2002 November	Callum Plant Acquired	Purchased a 50% interest in the Callum gas plant with 30 mmcf/d capacity, (28 mmcf/d unutilized) and 97 sections of undeveloped land for $14 million. The acquisition included 7.2 bcf of proved reserves.
2002 December	Facilities Full	The Mazeppa and Gladys gas plants, which process the majority of Compton's natural gas production, are operating at their maximum combined capacity of 88 mmcf/d.
2003 June	MPP Acquires Mazeppa and Gladys Plants	Mazeppa Processing Partnership acquired the Mazeppa and Gladys gas plants, including related compression facilities and pipelines in the area for $52 million. The acquisition provided Compton with virtual control over processing and infrastructure facilities in its Southern Alberta properties, and allowed the Company to immediately pursue and accelerate various processing alternatives, including plant expansions.

COMPTON'S GAS PLANT AT CALLUM IN SOUTHERN ALBERTA

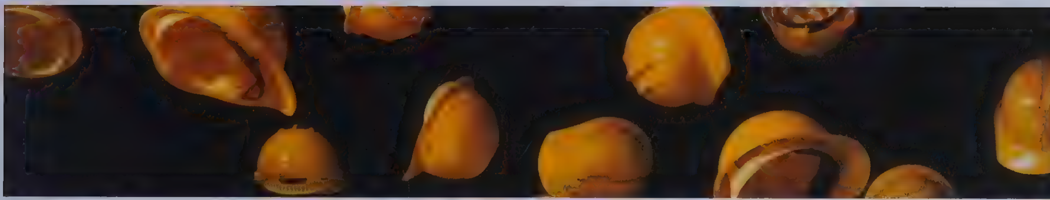
Timing	Event	Details
2003 Q2	Debottlenecking of Hooker Pipelines	Compton continued to debottleneck the Hooker pipeline system with the installation of 20 km of pipeline in the south end of Hooker.
2003 July	Offload Brant Production	The offloading of Brant gas production to the ATCO sales pipeline was completed and operational on July 25, 2003, resulting in 8 mmcf/d of capacity being available at Mazeppa which was immediately filled by existing gas behind pipe. The Brant gas plant has a capacity of 20 mmcf/d.
2003 Q3	All Hooker Pipeline Restrictions Removed	Compton completed the final step to remove all pipeline restrictions at Hooker with the twinning of 2.5 km of pipeline immediately south of the Mazeppa gas plant. The Hooker pipeline system capacity is now capable of handling 80 mmcf/d.
	Sour Gas Capacity Expanded at Mazeppa	Upgrades were completed to the condensate stabilizer tower, which increased the sour gas capacity of the Mazeppa plant by 10 mmcf/d to 90 mmcf/d.
2003 Q4	Sweet Gas Capacity Expanded at Mazeppa	Engineering and design of the 45 mmcf/d sweet gas expansion of the facilities at Mazeppa completed.
2004 May	Update on Sweet Gas Expansion	Expansion of the sweet gas processing capacity at Mazeppa completed and total capacity of the plant is 135 mmcf/d.
2004 Q1	Elimination of Processing & Pipeline Restrictions in Southern Alberta	Total Company processing capacity of Southern Alberta is now 172 mmcf/d.

Careful

Custody

WE BELIEVE

In the importance of ensuring that our employees, residents in the communities in which we operate and the environment in which we all live are protected as we conduct our exploration and development activities.



ENVIRONMENT, HEALTH & SAFETY AND COMMUNITY

The Engineering, Environmental, Health and Safety Committee of the Board has the responsibility to undertake with management those policies, guidelines, practices and procedures designed to manage risk and assume compliance with all workplace, environmental, health and safety laws to protect employees, community residents and the environment.

Environment

Compton believes in the importance of protecting the environment and is committed to conducting all operations in a safe manner that minimizes environmental impact. This commitment is demonstrated with the following initiatives and endeavors.

- The Company conducts annual environmental audits to ensure its facilities continually meet or exceed regulatory standards. Compton's policies require continuing compliance with the Alberta Environmental Protection and Enhancement Act.
- Compton evaluates the environmental impact of all new projects and ensures that effective controls are implemented. Any deficiencies that may occur are rectified in a timely and efficient manner.
- Compton supports individual and industry efforts to protect the environment and pursues a high standard of environmental management. The Company participates in the Canadian Association of Petroleum Producers' ("CAPP") Environment, Health and Stewardship Program.
- Compton has implemented appropriate management systems equivalent to CAPP's Basic Environment Program.
- Contractors working for Compton must also be dedicated to protecting the environment and must comply with the Company's policies and procedures, and all applicable laws and regulations.

Health and Safety

Compton is committed to operate in a safe manner, protecting the health and safety of employees, contractors and community residents. The Company's policy requires that all employees, contractors and subcontractors are made aware of and adhere to all safety practices governed by regulatory legislation, industry guidelines and the Company. Compton had no lost time accidents in 2003.

Compton also participates in CAPP's Stewardship Program, focused on continuous improvements in environment, health, safety and socio-economic performance. Compton has implemented Stewardship management systems and protocols, including the following.

- Management systems equivalent to the Petroleum Safety Council Basic Safety Program.
- Public consultation and community relations in accordance with the Alberta Energy and Utilities Board's guidelines as a minimum public notification basis and CAPP's Guide to Effective Public Involvement.
- Collecting and submitting stewardship benchmarking data.

Ensuring Accountability *and* Transparency

COMPTON UPHOLDS HIGH STANDARDS

Sound corporate governance ensures transparency and accountability for the Company's objectives, strategy, controls and overall performance.

The Board believes adopting and upholding the highest standards of corporate governance is critical for the overall success of Compton and to build stakeholder confidence. Sound corporate governance ensures transparency and accountability for the Company's objectives, strategy, controls and overall performance.

Compton's approach to corporate governance aligns closely with the Guidelines of the Toronto Stock Exchange ("TSX"). The TSX published proposed amendments to the Guidelines in 2002. Compton has reviewed its policies and practices against the proposed regulations and has adopted a policy of early compliance. Additionally, the Ontario Securities Commission has proposed Multilateral Instrument 58-101, "Disclosure of Corporate Governance Practices". The Company will continue to assess its corporate governance processes against new regulatory proposals.

Additionally, certain provisions of the Sarbanes-Oxley Act of 2002 and specific rules adopted and proposed by the United States Securities and Exchange Commission pursuant to the requirements of the Sarbanes-Oxley Act, are applicable to the Company due to the issuance of its senior term notes in May 2002.

The Governance and Compensation Committee of the Board continuously monitors, reviews and updates its corporate governance policies against all applicable proposed amendments to the TSX Guidelines, new legislation and regulations, applicable adopted and proposed provisions of the Sarbanes-Oxley Act of 2002 and special interest governance requests.

A more detailed description of Compton's governance practices can be found in the Company's Notice and Proxy Information Circular. The Charters of the Board and its Committees may be found on the Company's website at www.comptonpetroleum.com.

BOARD MANDATE AND COMPOSITION

The Board has explicitly assumed responsibility for the stewardship of the Company. The Board shall operate by delegating certain of its authorities, including the day to day conduct of the business of the Company, to Management and overseeing the activities of Management, while reserving certain powers for itself. The Board's fundamental objectives are to enhance and preserve long-term shareholder value and to provide stewardship in order that the Company meets its obligations on an ongoing basis and that the Company operates in a reliable and safe manner. As part of its stewardship responsibilities, the Board ensures that (i) the Company has established long-term goals and a strategic planning process; (ii) the principal risks of the Company's business are identified and appropriate systems are implemented to manage those risks; (iii) there is sufficient succession planning including managing and monitoring Management; (iv) the Company has a communications policy; and (v) the Company's internal controls and management information systems have sufficient integrity.

Compton is in full compliance with the TSX guidelines which provide that the board of every company should have a majority of individuals who qualify as unrelated Directors. Compton's Board is comprised of six Directors, five of whom, including the Chairman of the Board, qualify as unrelated Directors. Mr. Sapieha is a related Director because of his position as President & CEO of the Company. The remaining five Directors are independent, unrelated, outside Directors.

An "independent" director is a director who has no direct or indirect material relationship with the Company (a material relationship is a relationship which could, in the view of the Board, reasonably interfere with the exercise of a director's independent judgment).

An "unrelated" Director is a director who is (i) not a member of Management and is free from any interest and any business, family or other relationship which could, or could reasonably be perceived to, materially interfere with the Director's ability to act with a view to the best interests of the Company, other than interests and relationships arising from shareholding; (ii) not currently or has not been, within the last

three years, an officer, employee of or material service provider to the Company or any of its subsidiaries or affiliates; and (iii) not a director, officer employee or significant shareholder of an entity that has a material business relationship with the Company.

An "outside" Director is not a member of the Company's Management. Additionally, no Board members sit on other boards together, in order that there are no inter-related interests.

The Board of Directors met eleven times in 2003 and all members attended the meetings. Mr. Thomson attended all meetings after his election as a director of the Company on June 3, 2003. A full copy of the Charter for the Board of Directors can be found on the Company's website at www.compton petroleum.com.

COMMITTEES OF THE BOARD

Subject to applicable law, the Board may delegate its powers, duties and responsibilities to Committees of the Board. In this regard, the Board has established three standing Committees: Governance and Compensation; Audit, Finance and Risk; and Engineering, Environmental, Health and Safety. The mandate of each committee is reviewed annually and is summarized below. All Committees are composed exclusively of independent, outside, unrelated Directors.

Governance and Compensation Committee

Chairman: Mel Belich
Members: Irv Koop, John Preston, Jeff Smith, John Thomson

The Committee's mandate is to be responsible for developing the Company's approach to governance issues and to assist the Board in fulfilling its oversight responsibilities with respect to the development and implementation of principles for the management of corporate governance with a view to fostering a culture of integrity within the Company.

The Committee also has the responsibility to:

1. recommend initiatives to maintain high standards of corporate governance;
2. review and oversee human resources policies of the Company;
3. review succession plans for key Management positions within the Company;
4. develop performance objectives for the CEO and other Officers and assess their performance against such objectives;
5. recommend to the Board, salary and other remuneration for Officers of the Company. The Committee also monitors performance objectives for Officers in order that they are aligned with shareholders' interests and corporate goals;
6. recommend to the Board in respect of all other compensation matters, including long and short-term incentives such as bonuses, stock option plans and other benefits;
7. assess the effectiveness and performance of the Board as a whole, its Committees and individual Directors;
8. define and monitor the relationship, roles and authority of the Board and Management;
9. recommend candidates to the Board for nomination as Directors;
10. define the structure and composition of the Board and its Committees;
11. review and recommend compensation for Board and Committee service; and
12. review and evaluate corporate communication policies and practices.

The Governance and Compensation Committee met six times in 2003 and all members attended the meetings. Mr. Thomson attended all meetings after his election as a Director of the Company on June 3, 2003.

The full Governance and Compensation Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

Audit, Finance and Risk Committee

Chairman: Irv Koop
Members: Mel Belich, John Preston, Jeff Smith, John Thomson

The Audit, Finance and Risk Committee is mandated to oversee that Management is responsible for creating and maintaining an effective risk management and internal control framework. This framework provides reasonable assurance that the financial, operational and regulatory objectives of the Company are achieved and that the statutory responsibilities of Board are discharged.

The Committee fulfills its role on behalf of the Board, by overseeing:

1. the review, disclosure and integrity of the Company's financial statements, Management's Discussion and Analysis of financial conditions and results of operations and other financial information;
2. the external auditor's qualifications, independence and performance;
3. the Company's compliance with legal and regulatory requirements;
4. risk management, management information systems, governmental legislation and external business of the Company;
5. the effectiveness and integrity of the Company's system of disclosure controls and internal controls; and
6. the appointment of the Chief Financial Officer and other key financial executives.

The Committee also oversees the operation of an anonymous and confidential toll free telephone number for employees, contractors and others to call with respect to accounting irregularities or ethical violations, and has established a procedure for the receipt, retention, treatment and regular review of any such reported activities. This telephone number is published on the Compton's website at www.compton petroleum.com.

The Committee met seven times in 2003 and all members attended the meetings. Mr. Thomson attended all meetings after his election as a Director of the Company on June 3, 2003.

The full Audit, Finance and Risk Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

Engineering, Environmental, Health and Safety Committee

Chairman: Jeff Smith
Members: Mel Belich, Irv Koop, John Preston, John Thomson

The Committee's mandate is to review and make recommendations to the Board on the Company's engineering and reserves policies. Additionally the Committee monitors the environmental, health and safety practices and procedures of the Company for compliance with applicable legislation, conformity with industry standards and prevention or mitigation of loss.

The Committee fulfills its oversight role on behalf of the Board and is responsible for:

1. the Company's overall policies and guidelines with respect to (i) engineering and reserves and (ii) environmental, health and safety matters regarding the Company's facilities and operations;
2. undertaking with Management all necessary procedures and policies to comply with regulations and guidelines applicable to the Company and enunciated by the applicable regulatory authorities including providing assistance to management in compliance with National Instrument 51-101, preparation of the Statement of Reserves (Form 51-101F1), Evaluator Report (Form 51-101F2) and Management Report (Form NI 51-101F3);
3. reviewing, assisting and making recommendations to the Board in respect of the annual appointment of the Company's independent qualified reserves evaluators;

4. undertaking with management those policies, guidelines, practices and procedures designed to manage risk and assume compliance with all workplace, environmental, health and safety laws;
5. reviewing and monitoring the Company's policies, procedures and practices relating to the documentation and reporting of environmental, health and safety regulatory approvals, compliance and incidents; and
6. generally, reviewing the Company's performance related to environment, health and safety and confirming with management that long-range preventative programs are in place.

The Engineering, Environmental, Health and Safety Committee met five times in 2003 and all members attended the meetings. Mr. Thomson attended all meetings after his election as a Director of the Company on June 3, 2003.

The full Engineering, Environmental, Health and Safety Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

CODE OF BUSINESS CONDUCT AND ETHICS

Compton's Code of Business Conduct and Ethics holds the Company's Directors, Officers, employees and consultants to high standards of legal and moral conduct in all areas of operations. In addition to simply meeting legal and regulatory requirements, the Company strives to conduct all operations fairly and with integrity. Compton's Code of Business Conduct and Ethics may be viewed on the Company's website at www.comptonpetroleum.com.

CORPORATE CITIZENSHIP

Compton recognizes the importance and positive impact that results from responsible corporate citizenship. The Company believes in giving back to the communities in which it conducts operations and supported numerous local initiatives through out the year.

Educational Partnerships

For the past three years, Compton has formed a Corporate/Educational Partnership with a Calgary Board of Education Public School. During the 2002-2003 school year, Compton partnered with Alex Munro Elementary School. Compton supported the students by funding a collection of Canadian literature for the school library and purchasing a commemorative book – "M is for Maple" by Mike Ulmer for all students. Students also attended a Canadian film at the Imax theatre and a French Canadian performance by Les Bucheron.

Compton is participating in an educational partnership with Douglas Harkness Elementary School during the 2003-2004 school year. Compton purchased a new sound system for the school's Performing Arts Program and further initiatives will be undertaken throughout the school year.

Community Partnerships

The Company's Corporate Sponsorship and Donation Programs contribute to charities and community endeavors that enhance the quality of life in the areas where Compton is active.

Corporate donations were made to the High River Rotary and Kinsmen club projects, Nanton Community blood donor clinic, Calgary Police Street Teams/Safe House Society, Calgary Firefighters' Burn Unit, Longview Library, Juvenile Diabetes Research Foundation, Boys and Girls Clubs, CAPL Scholarship Fund, Canadian Cancer Society, Missing Children's Fund, Alberta Children's Hospital, Big Brothers and Sisters and YMCA Calgary.

Protecting the environment, environmentally responsible practices and related charitable causes continue to be a priority for the Company. During 2003, Compton once again joined Ducks Unlimited Canada as a corporate sponsor. Ducks Unlimited conserves, restores and manages wetlands and associated habitats for North America's waterfowl.

MEL F. BELICH Q.C., CHAIRMAN

Chairman and President of Enbridge International Inc. and Enbridge Technology Inc., and Group Vice President – International and Corporate Law, Enbridge Inc., an energy transportation and distribution company.

Mr. Belich is the Chairman of the Board of Directors of Compton and the Chairman of the Governance and Compensation Committee.

IRVINE J. KOOP, P. ENG.

Chairman and Chief Executive Officer, IKO Resources Inc., a petroleum consulting firm and prior thereto was President and CEO, Pipelines and Midstream of Westcoast Energy Inc.

Mr. Koop is the Chairman of the Audit, Finance and Risk Committee.

JOHN W. PRESTON

Account Executive, Sun Microsystems of Canada Inc., a computer company.

Providing sound advice and strong

Guidance

JEFFREY T. SMITH, P. GEOL.

Independent Businessman and prior thereto, Chief Operating Officer of Northstar Energy Corporation.

Mr. Smith is Chairman of the Engineering, Environmental, Health and Safety Committee.

ERNIE G. SAPIEHA, C.A.

President & Chief Executive Officer of the Company.

JOHN A. THOMSON, C.A.

Independent Businessman and prior thereto Senior Vice President and Chief Financial Officer of Renaissance Energy Ltd.

Taking care of our financial

Resources

COMPTON IS DEDICATED

to building an exploration and development company capable of delivering and sustaining long-term growth.

Management's Discussion and Analysis ("MD&A") is intended to provide both an historical and prospective view of the Company's activities. The MD&A was prepared as at April 19, 2004 and should be read in conjunction with the audited consolidated financial statements and related notes for the year ended December 31, 2003. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation to United States GAAP is included in Note 18 to the consolidated financial statements.

and reporting the Results

Management's Discussion and Analysis may contain certain forward-looking statements under the meaning of applicable securities laws. Forward-looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact. Although Compton Petroleum Corporation ("Compton" or "the Company") believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. There are many factors that could cause forward-looking statements not to be correct, including risks and uncertainties inherent in the Company business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate fluctuations, availability of services and supplies, operating hazards and mechanical failures, uncertainties in the estimates of reserves and in projections of future rates of production and timing of development expenditures, general economic conditions, and the actions or inactions of third-party operators. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement.

Management's Discussion and Analysis contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than "cash flow from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Company's financial performance. Compton's determination of cash flow from operations may not be comparable to that reported by other companies. The other items required to arrive at cash flow from operating activities are considered to be corporate charges.

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent basis ("boe") whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. In several sections that follow, Compton has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. However, boe's do not represent a value equivalency at the plant gate where Compton sells its production volumes and therefore may be a misleading measure if used in isolation.

OVERVIEW

Compton is an independent, public company actively engaged in the exploration, development and production of natural gas, natural gas liquids, and crude oil in Western Canada. The Company's activities are concentrated in three core geographic areas in the Western Canadian Sedimentary Basin, primarily in Alberta. Compton's growth and reserves base have resulted from exploration and development activities, complemented by strategic acquisitions. Additionally, Compton controls and manages the Mazeppa Processing Partnership ("MPP"), which owns significant midstream assets critical to the Company's activities in Southern Alberta. The accounts of MPP are consolidated and reflected as a separate business unit.

Management's Strategy

Compton's objective has been and remains that of building an exploration and development company capable of delivering and sustaining long-term growth. Management has adhered to a consistent strategy in pursuing this objective.

Major components of Management's strategy currently include:

- an emphasis on natural gas with a particular focus on unconventional tight gas reserves;
- focus in a limited number of core areas;
- development of technical expertise;
- dominant land position and high working interests;
- control of infrastructure and operatorship;
- full-cycle exploration; and
- strategic acquisitions.

Mazeppa Processing Partnership

Mazeppa Processing Partnership is a limited partnership organized under the laws of the province of Alberta. In June 2003, MPP acquired certain midstream assets in southern Alberta from an independent third party. These midstream assets consist of major natural gas gathering and processing facilities that are critical to Compton's operations in the area.

Compton has minimal ownership in MPP, however, the Company controls and manages the activities of MPP through a wholly-owned subsidiary that is the General Partner of MPP. The consolidated financial statements include the accounts of MPP.

The operations of MPP are considered to be a business segment separate and distinct from the Company's exploration, exploitation, development and production activities ("E&P activities"). Segmented information is presented in Note 4 to the consolidated financial statements and is reflected elsewhere in the MD&A.

Production

Years ended December 31,	2003	2002	2001
Natural gas *(mmcf/d)*	**118**	112	101
Liquids (light oil & ngl's) *(bbls/d)*	**5,924**	6,503	6,546
Total oil equivalent *(boe/d)*	**25,552**	25,137	23,404

Average production in 2003 was 25,552 boe/d, a slight increase from 2002 production of 25,137 boe/d. Production growth in 2003 was constrained by weather related delays, plant turnarounds, and most significantly, insufficient processing and pipeline capacity in Southern Alberta. Several initiatives were undertaken by the Company in 2003 to expand facilities and the production restraints were eliminated in the second quarter of 2004.

Compton's production profile continues to reflect the Company's focus on natural gas, which accounted for approximately 77% of the current year's production. Natural gas production averaged 118 mmcf/d in 2003, a 5% increase from 2002, while liquids production decreased by 9% to 5,924 bbls/d.

Cash Flow and Net Earnings

Years ended December 31,		2003	2002	2001
Cash flow from operations *($000s)*		**$ 154,893**	$ 96,072	$ 127,861
Per share:	basic	**$ 1.33**	$ 0.85	$ 1.16
	diluted	**$ 1.27**	$ 0.81	$ 1.11
Net earnings *($000s)*		**$ 118,880**	$ 18,312	$ 55,015
Per share:	basic	**$ 1.02**	$ 0.16	$ 0.50
	diluted	**$ 0.97**	$ 0.16	$ 0.48

Cash flow from operations in 2003 was $155 million ($1.33/share basic), a 61% increase from the previous year. Net earnings for the year totaled $119 million ($1.02/share basic), as compared to $18 million in 2002. MPP did not have a material impact on Compton's 2003 net earnings or cash flow from operations.

Current year cash flow and net earnings benefited from higher commodity prices. The average price per boe received by the Company in 2003 increased 50% from 2002. In addition to higher commodity prices, net earnings in the current year included a $39 million after tax unrealized foreign exchange gain on the Company's U.S. dollar denominated debt and a $37 million recovery of future income taxes relating to statutory income tax rate changes. Net earnings excluding these items was $43 million, an increase of 134% over 2002.

FINANCIAL RESULTS

Revenue and Pricing

	2003		2002		2001	
Years ended December 31,	($000s)	%	($000s)	%	($000s)	%
Natural gas revenue	**$ 262,203**	**78**	$ 148,133	67	$ 174,424	71
Natural gas hedging impact	**(3,947)**	**(1)**	1,789	1	3,666	1
Crude oil and ngls revenue	**76,051**	**23**	70,297	32	66,880	28
Crude oil hedging impact	**(1,548)**	**(0.5)**	(432)	–	–	–
Processing revenue	**1,934**	**0.5**	–	–	–	–
Total revenue	**$ 334,693**	**100**	$ 219,787	100	$ 244,970	100

Compton realized $333 million in petroleum and natural gas revenue in 2003, up 51% from the previous year. The increase in revenue resulted primarily from higher realized prices in 2003. Compton's average

realized natural gas price rose 66% from 2002 to $6.10/mcf in 2003 before hedge losses. The average realized liquids price in 2003 was $35.11/bb1 before hedge losses, a 19% increase from 2002.

Processing revenue in 2003 results from the consolidation of MPP and reflects third party natural gas processing fees.

In 2003, the Company's average realized field prices in Canadian funds were $6.01/mcf of natural gas and $34.39/bbl for crude oil and natural gas liquids, compared to the 2002 average field prices of $3.67/mcf and $29.43/bbl for natural gas and natural gas liquids respectively.

Compton's natural gas production is sold under a combination of longer-term contracts with aggregators and short-term daily or 30-day AECO-indexed contracts. Approximately 16% of the Company's natural gas production in 2003 was committed to aggregators, compared to an average of 35% in 2002. The average aggregator price realized in 2003 was approximately $1.00/mcf less than the non-aggregator prices realized during the year.

Compton's crude oil sales are priced at Edmonton postings and are typically sold on 30-day evergreen arrangements. Natural gas liquids are bid out on an annual basis to establish the most competitive pricing. The Company sells crude oil and natural gas liquids primarily to refineries and marketers of crude oil and natural gas liquids.

From time to time, Compton may enter into hedging arrangements to mitigate commodity price risk. In accordance with Compton's policy, hedging programs will not exceed 50% of non-contracted production. See Financial Instruments discussion for outstanding hedges.

Royalties

Years ended December 31, ($000s, except where noted)	2003	2002	2001
Crown royalties	$ 68,360	$ 38,902	$ 44,075
Other royalties	14,706	9,095	12,344
	83,066	47,997	56,419
Alberta royalty tax credit	(500)	(500)	(500)
Net royalties	$ 82,566	$ 47,497	$ 55,919
Percentage of oil and gas revenues	24.7%	21.6%	22.8%

The Company's royalty obligations for 2003, net of the Alberta royalty tax credit, amounted to $83 million, a 74% increase from 2002 royalties. The increase is attributable to higher prices in the current year and the effects of the provincial sliding-scale Crown royalty structure, which imposes higher royalty rates at higher commodity prices.

Operating Expenses

Years ended December 31, ($000s, except where noted)	2003	2002	2001
E&P activities	$ 52,733	$ 45,546	$ 40,222
MPP (recovery)	(745)	–	–
Total operating expenses	$ 51,988	$ 45,546	$ 40,222
E&P operating expenses per boe *($/boe)*	$ 5.65	$ 4.96	$ 4.71

On a unit-of-production basis, oil and natural gas operating costs were $5.65/boe, a 14% increase from operating costs per boe in 2002. The major contributors to this increase were the overall rise in the cost of goods and services in the oil and natural gas industry, additional field staff required for expanding operations and higher energy costs.

General and Administrative Expenses

Years ended December 31, ($000s, except where noted)	2003	2002	2001
E&P general and administrative expense	$ 20,141	$ 16,145	$ 12,628
Capitalized general and administrative expense	(3,321)	(2,689)	(2,543)
Operating recoveries	(4,828)	(3,611)	(3,503)
Net general and administrative expense	11,992	9,845	6,582
MPP general and administrative expense	214	–	–
Total general and administrative expense	$ 12,206	$ 9,845	$ 6,582
Net E&P general and administrative per boe *($/boe)*	$ 1.29	$ 1.07	$ 0.77

On a boe basis, net E&P G&A costs were $1.29, a 21% increase from $1.07/boe incurred in 2002. Additional full-time employees required due to the expanded activities of the Company, additional regulatory and reporting related costs and higher insurance costs contributed to increased G&A in 2003.

Interest Expense

Years ended December 31, ($000s)	2003	2002	2001
Interest expense	$ 29,230	$ 20,130	$ 12,863
Average debt outstanding	$ 339,190	$ 265,605	$ 203,410

Interest expense increased in 2003 due to higher overall debt levels. The average debt outstanding rose in 2003 as the Company increased the amount drawn on its syndicated credit facility to fund MPP's acquisition and expansion of the Mazeppa and Gladys gas plants and related infrastructure. Additionally, debt increased as total capital expenditures in 2003 exceeded the current year's cash flow.

Netbacks

The following netbacks represent the financial results of the Company's E&P segment, as summarized in Note 4 to the consolidated financial statements. MPP activities are excluded.

	2003			2002	2001
Years ended December 31,	Natural gas ($/mcf)	Crude oil and ngls ($/bbl)	Total ($/boe)	($/boe)	($/boe)
Realized price	$ 6.10	$ 35.11	$ 36.25	$ 23.95	$ 28.68
Royalties, net	(1.48)	(8.84)	(8.84)	(5.17)	(6.55)
Operating expenses	(0.93)	(5.65)	(5.65)	(4.96)	(4.71)
Field operating netback excluding hedge	$ 3.69	$ 20.62	$ 21.76	$ 13.82	$ 17.42
Financial hedge	(0.09)	(0.72)	(0.59)	–	–
Netback including hedge	$ 3.60	$ 19.90	$ 21.17	$ 13.82	$ 17.42
General and administrative			(1.29)	(1.07)	(0.77)
Interest			(3.13)	(2.19)	(1.51)
Capital taxes			(0.26)	(0.17)	(0.16)
Cash flow netback			$ 16.49	$ 10.39	$ 14.98

Depletion, Depreciation and Asset Retirement Costs

Years ended December 31, ($000s, except where noted)	2003	2002	2001
E&P activities	$ 60,631	$ 55,473	$ 50,283
MPP	1,118	–	–
Total expense	$ 61,749	$ 55,473	$ 50,283
E&P depletion and depreciation expense per boe *($/boe)*	$ 6.50	$ 6.05	$ 5.89

Capital expenditures in the current year, future capital expenditures relating to the development of proved non-producing reserves and the adoption of the asset retirement obligations accounting policy increased the Company's depletion base and depletion expense in 2003.

Taxes

CURRENT TAXES

Current taxes include federal large corporations tax ("LCT"). In 2003, LCT increased approximately $1 million over 2002 due to an increase in the Company's capital base upon which the LCT is calculated. This tax is non-deductible and increases as the capital resources of the Company increase. Also included in current taxes is $800,000 resulting from reassessment of 2000 income taxes relating to the reclassification of exploration expenses.

FUTURE INCOME TAX EXPENSE

The Company's future income taxes were $20 million in 2003, comparable to $19 million in 2002. Earnings before income taxes increased significantly in 2003 over 2002, however, future income taxes in 2003 are approximately $1 million less than 2002 as a result of a $37 million future tax recovery resulting from a decrease in statutory income tax rates.

TAX POOLS

The following table summarizes the Company's estimated tax pool balances by classification.

As at January 1, 2004	Available Balance ($000s)	Maximum Annual Deduction
Non-capital losses	$ 2,708	100%
Canadian exploration expense	26,847	100%
Canadian development expense	98,980	30%
Canadian oil and natural gas property expense	166,895	10%
Undepreciated capital cost	95,508	4%-100%
Total	$ 390,938	

The Company may be marginally cash taxable in 2004, depending upon the nature and level of capital expenditures and commodity prices.

LIQUIDITY AND CAPITAL RESOURCES

The Company believes its existing credit facilities and capital resources are sufficient to support its capital investment programs and future growth prospects, in addition to enabling the Company to meet all other current and expected financial requirements.

The capitalization of the Company at December 31, 2003 consists primarily of $357 million of shareholders' equity, $213 million senior term notes (U.S. $165 million) and $165 million drawn on the Company's syndicated credit facility, including the $65 million advanced to MPP to fund the purchase of the Mazeppa and Gladys gas plants and expand the facilities. Total debt outstanding at year-end, net of working capital, was $353 million.

Compton expects funds generated from operations, $30 million of minor non-operated property dispositions and funds available under the Company's existing bank credit facilities, will be sufficient to finance operations and planned capital expenditures of $200 million for 2004. The Company's capital expenditure budget can be adjusted as required. During 2004, the Company expects to renew its credit facilities with its syndicate of Canadian lenders. The facility is currently set at $215 million, although a borrowing base of $240 million was established by syndicate members.

Contractual Obligations

As part of normal business, the Company entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity, some of which are reflected as liabilities in the consolidated financial statements. Principal commitments of the Company are in the form of debt repayments, and lease operating commitments. The following table summarizes the Company's contractual obligations.

	Payments Due by Period			
As at December 31, 2003 ($000s)	Less than 1 year	2-3 years	4-5 years	After 5 years
Capital lease obligations	$ 36	$ 91	$ –	$ –
Operating leases	1,622	4,097	–	–
Office rent	1,452	481	–	–
Other long term obligations	–	–	–	213,246
Total	$ 3,110	$ 4,669	$ –	$ 213,246

The Company intends to and has the ability to extend the term of its current borrowings of $165 million on an ongoing basis under its syndicated credit facility and therefore repayment of the facility is not included in the schedule of contractual obligations above.

OPERATING RESULTS

In 2003, the Canadian Securities Administrators adopted National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities". These standards require certain information to be filed on SEDAR, "System for Electronic Disclosure Analysis and Retrieval" and are intended to ensure that all public oil and natural gas companies disclose similar information prepared on the same basis. Compton has filed the required Form NI 51-101F1 as part of its Annual Information Form ("AIF") which is available on both the SEDAR website and Compton's website. The AIF is very comprehensive, therefore certain information has been extracted with respect to operations and presented in the following sections. All such information is consistent with the Form NI 51-101F1 filing.

Undeveloped Land

In 2003, Compton continued to expand its land base in its core areas. The Company's total land position at December 31, 2003 consisted of 1,080,798 net acres. Undeveloped land increased to 767,364 net acres, sufficient to provide the Company with approximately five years of internal drilling prospects. Land acquisitions during 2003 occurred primarily in the Company's core areas in Southern and Central Alberta. The Company has an average 74% working interest in its undeveloped land base.

Compton's undeveloped land holdings are as follows.

As at December 31, 2003	Undeveloped Acres		Undeveloped Sections	
Area	Gross	Net	Gross	Net
Southern Alberta	480,859	399,736	751	625
Central Alberta	284,696	181,801	445	284
Peace River Arch	136,713	93,608	213	146
Northern Alberta	96,748	74,733	151	117
Other	43,786	17,486	69	27
December 31, 2003 Total	**1,042,802**	**767,364**	**1,629**	**1,199**
December 31, 2002 Total	1,042,923	742,465	1,630	1,160
December 31, 2001 Total	962,259	700,695	1,504	1,095

Capital Expenditures

The Company continued to invest in land, production facilities and exploratory drilling necessary for future growth. Total capital expenditures in the current year were $221 million, excluding the MPP midstream assets, a 42% increase from the prior year.

Drilling and completions expenditures increased 68%, as the Company drilled almost double the number of wells in 2003 as in 2002. Spending on land and seismic increased from the previous year. Land prices in Alberta are currently higher than historical averages due to increased competition in the oil and natural gas industry. Facilities expenditures more than doubled from 2002, consistent with increased drilling activity and compression requirements associated with the tie-in of lower pressure Belly River wells.

	2003		2002		2001	
Years ended December 31,	(000s)	%	(000s)	%	(000s)	%
Drilling and completions	$ 126,308	57	$ 75,369	48	$ 84,658	44
Land and seismic	37,128	17	29,096	19	25,883	14
Facilities	46,068	21	21,714	14	27,643	15
Acquisitions, net	11,224	5	28,929	19	22,614	11
Sub-total, E&P	220,728	100	155,108	100	160,798	84
Corporate acquisitions	–	–	–	–	29,669	16
Sub-total	220,728	100	155,108	100	190,467	100
MPP	64,755		–		–	
Total	$ 285,483		$ 155,108		$ 190,467	

Compton has budgeted $200 million for capital expenditures in 2004. The areas of spending will be similar to 2003, excluding MPP.

Drilling Activity

Compton drilled 168 gross (134 net) wells in 2003 with an 83% success rate, compared with 87 gross (64 net) wells drilled in 2002. Drilling activity in 2003 increased primarily in the Company's Southern and Central Alberta core areas. The Company drilled 30 additional wells targeting Belly River sands and six additional wells targeting the Basal Quartz zone in Southern Alberta in 2003. In Central Alberta, 14 additional wells were drilled into the Company's Niton lands and six additional wells were drilled at Thornbury, compared to 2002 drilling. The remaining increase in drilling was evenly distributed across Compton's core areas.

Of the 168 wells drilled in 2003, 43% were classified as exploratory wells and 57% were classified as development wells. Seven of the wells drilled are standing cased wells and are awaiting completion and testing. These wells are not included in the following table.

Years ended December 31,	Natural Gas	Oil	D&A	Total	Net	Success
Southern Alberta	82	4	13	99	89	86%
Central Alberta	26	2	5	33	18	66%
Peace River Arch	7	12	10	29	22	87%
2003 Total	**115**	**18**	**28**	**161**	**129**	**83%**
2002 Total	64	14	9	87	64	90%
2001 Total	60	12	23	95	71	76%

Reserves

Compton engaged the international, integrated petroleum engineering and geological consulting firm of Netherland Sewell & Associates, Inc. ("Netherland Sewell") as independent reserve evaluators for Compton's reporting period ending on December 31, 2003. Netherland Sewell's evaluation, conducted in accordance with the stringent new standards of National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") confirmed Compton's high quality, long life, predominately natural gas weighted reserve base.

The Company's proved reserves, after production, increased 3% to 85 million boe. Proved plus probable reserves, after production, increased 15% to 119 million boe, compared to 2002 established reserves.

	Crude Oil(1)		Natural Gas(1)		NGL's(1)		Total(1)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
As at December 31, 2003	(mbbl)	(mbbl)	(bcf)	(bcf)	(mbbl)	(mbbl)	(mboe)	(mboe)
Proved:								
Developed producing	6,530	6,059	322	263	6,592	4,957	66,806	54,849
Developed non-producing	163	159	32	24	575	375	5,996	4,534
Undeveloped	2,494	1,945	49	38	1,120	784	11,825	9,062
Total proved	**9,187**	**8,163**	**403**	**325**	**8,287**	**6,116**	**84,627**	**68,445**
Probable	2,847	2,016	165	135	3,741	2,801	34,136	27,317
Total proved plus probable	**12,034**	**10,179**	**568**	**460**	**12,028**	**8,917**	**118,763**	**95,762**

(1) Does not include royalty interest equivalent barrels.

RESERVE RECONCILIATION (NET AFTER ROYALTIES)

As at December 31, 2003	Crude Oil and NGL's[1] Net Proved (mbbl)	Net Probable (mbbl)	Net Proved plus Probable (mbbl)	Natural Gas[1] Net Proved (mmcf)	Net Probable (mmcf)	Net Proved plus Probable (mmcf)
December 31, 2002	11,884	4,116	16,000	310,419	72,512	382,931
Extensions	1,397	–	1,397	9,940	226	10,166
Improved recovery	810	139	949	6,595	(293)	6,302
Technical revisions	604	(923)	(319)	(10,443)	861	(9,582)
Discoveries	661	1,180	1,841	37,593	62,670	100,263
Acquisitions	404	–	404	2,333	–	2,333
Economic factors	344	304	648	86	(629)	(543)
Production	(1,824)	–	(1,824)	(31,568)	–	(31,568)
December 31, 2003	**14,280**	**4,816**	**19,096**	**324,955**	**135,347**	**460,302**

(1) *Does not include royalty interest equivalent barrels.*

Compton's proved plus probable reserves were evaluated at over $1 billion, 8% DCF or $895 million, 10% DCF.

NET PRESENT VALUE OF RESERVES, FORECAST PRICES AND COSTS

As at December 31, 2003 ($000s)	Future net revenue before income taxes[1] discounted at a rate of 0%	8%	10%
Proved:			
Producing	$ 1,193,296	$ 622,778	$ 564,889
Non-producing	102,776	58,159	52,574
Undeveloped	218,206	88,995	75,136
Total proved	**$ 1,514,278**	**$ 769,932**	**$ 692,599**
Probable	612,247	241,515	202,551
Total proved plus probable	**$ 2,126,525**	**$ 1,011,447**	**$ 895,150**

(1) *As an independent reserves evaluator, Netherland Sewell does not provide price forecasts. April 1, 2004 pricing forecasts prepared by McDaniel & Associates Consultants Ltd. were utilized in determining the future net revenues presented above. These forecasts are below current forward prices.*

The net present value should not be considered the current market value of the Company's reserves or the costs that would be incurred to obtain equivalent reserves.

Finding & Development Costs

Finding, development and acquisition ("FD&A") costs associated with the 2003 exploration and development program, calculated in accordance with NI 51-101 and including revisions and changes in future capital were $20.91/boe on a proved basis and $14.11/boe on a proved plus probable basis. Excluding acquisitions, finding and development ("F&D") costs were $21.71/boe proved and $14.20/boe proved plus probable.

It should be noted that the aggregate of the exploration and development costs incurred in 2003 and the change during the year in estimated future development costs, generally will not reflect total F&D costs related to reserves additions for the year.

Periods ending December 31, ($/boe)	2003	2002	2001	3 year Average	5 year Average
F&D costs, proved	$ 21.71	$ 8.16	$ 10.78	$ 12.53	$ 12.18
F&D costs, proved plus probable (1)	$ 14.20	$ 5.79	$ 11.76	$ 10.22	$ 9.86
FD&A costs, proved	$ 20.91	$ 8.15	$ 9.92	$ 11.80	$ 10.94
FD&A costs, proved plus probable (1)	$ 14.11	$ 6.08	$ 10.18	$ 9.87	$ 9.21

Calculated using proved plus risked probable (established) reserves for 2002 and 2001.

ADDITIONAL DISCLOSURES

Critical Accounting Estimates

Critical accounting estimates require Management to make assumptions regarding matters that are highly uncertain at the time the estimate is made and have a material impact on the financial condition of the Company. A comprehensive discussion of the Company's significant accounting policies may be found in Notes 1 and 2 to the consolidated financial statements.

OIL AND NATURAL GAS RESERVES

Compton's oil and natural gas reserves were evaluated and reported on by the independent petroleum engineering and geological consulting firm of Netherland Sewell which evaluated 100% of the Company's reserves.

The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change with updated information from the results of future drilling, testing or production levels. Such revisions could be upwards or downwards. Reserve estimates have a material impact on depletion and depreciation expense, asset retirement costs and impairment expense, which could possibly have a material impact on consolidated net income.

DEPLETION

Capitalized costs and estimated future expenditures to develop proved reserves, including abandonment costs, are depleted based on the proportion of estimated proved oil and natural gas reserves produced during the year compared to total proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If it is determined that properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

In 2003, Compton incurred $62 million of depletion and depreciation. If the proved reserves of the Company were to vary by 5%, the depletion and depreciation expense would change by approximately $800,000 and consolidated net income after tax would change by approximately $480,000.

IMPAIRMENT

In applying the full cost method of accounting, Compton periodically calculates a ceiling, or limitation on the amount that property and equipment may be carried for on the balance sheet. An impairment exists if the undiscounted future net cash flows from proved reserves at future commodity prices plus the cost of undeveloped properties is less than the carrying value of the capitalized costs. If an impairment is found to exist, the impaired properties are written down to their fair value. The fair value of the assets is calculated based on future net cash flows from proved plus probable reserves, discounted at a risk free rate using future commodity prices, plus the cost of undeveloped properties. An impairment may result in a material loss for a particular period; however, future depletion and depreciation expense would be reduced.

Assumptions about reserves and future prices are required to calculate future net cash flows. The assumptions made to estimate reserves have been previously discussed. There is significant uncertainty regarding forecasting future commodity prices due to economic and political uncertainty. Future prices are derived from a consensus of price forecasts among recognized reserve evaluators. Estimates of future cash flows assume a long-term price forecast and current operating costs per boe plus an inflation factor.

It is difficult to determine and assess the impact of a decrease in proved reserves on impairment. The relationship between reserve estimates and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test, is complex. As a result, it is not possible to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on impairment. No material downward revisions to the Company's reserves are anticipated.

ASSET RETIREMENT OBLIGATION

Compton is required to remove production equipment, batteries, pipelines, gas plants and restore land at the end of oil and natural gas operations. The Company estimates these costs in accordance with existing laws, contracts and other policies. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is also capitalized as part of the cost of the related assets and amortized over the useful life of the assets.

An annual increase to the liability will be recorded to recognize the passage of time and the impending settlement of the obligation. The liability will be impacted by any changes in the assumptions used in the asset retirement obligation ("ARO") calculation. Adjustments to the estimate will be recorded as an accretion expense on the consolidated statements of earnings.

In the future, the Company's depletion expense will be reduced since the discounted future value of the liability will be depleted rather than the undiscounted value previously depleted. The lower depletion expense will be offset by the addition of the accretion expense.

An independent environmental consulting firm was hired to assist management in the estimation of asset removal costs. The ARO cost calculations were derived from a combination of actual third party cost quotes, Alberta Energy and Utility Board cost models and typical industry experience and practices. The deemed ARO liability for wells and facilities is the sum of the calculated abandonment and reclamation liabilities adjusted for designated status as active, inactive, abandoned, or problem site. Information regarding environmental remediation costs and other liability issues for site-specific concerns were derived from a review of historical audits and assessment reports for sites and facilities. An inflation rate of 2.0% and a credit adjusted risk free discount rate of 10.6% was used in Compton's fair value calculation.

Estimating future asset removal costs is difficult and requires Management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as well as regulatory, political, environmental, safety and public relations considerations. As a result, it is not possible to provide a reasonable analysis of the impact that changes in removal costs would have on the asset retirement obligation. If the inflation rate assumed in the ARO calculation changed by 1%, the ARO obligation would vary by $3 million. Additionally, a 1% change in the credit adjusted risk free interest rate would result in a $2 million change to the ARO liability.

Changes in Accounting Policy

STOCK BASED COMPENSATION

In November 2003, Canadian Institute of Chartered Accountants ("CICA") amended Handbook Section 3870, "Stock Based Compensation" requiring companies to use the fair value method of accounting for stock based payments. Under this method the fair value of stock based compensation, such as stock options, is recognized as a compensation expense over the vesting period. Adoption of the amended section was required on or after January 1, 2004, however Compton chose to early adopt effective January 1, 2003.

Section 3870 provides alternative methods of transition to the fair value method, including:

- retroactive application, with prior period restatement;
- retroactive application, with adjustment of opening retained earnings; or
- prospective application, with no restatement of prior years.

The difference of the impact on the financial condition of the Company in 2003 between the alternative adoption methods was immaterial. Compton elected to apply the amended standard prospectively and recognized $1 million of compensation expense for options granted during 2003. Had the fair value method been adopted retroactively, it would have resulted in an impact on net income as outlined in Note 10 to the consolidated financial statements.

ASSET RETIREMENT OBLIGATIONS

In December 2002, the CICA approved Handbook Section 3110, "Asset Retirement Obligations," requiring recognition for asset retirement obligations and costs associated with the Company's oil and gas properties, plants and equipment. Adoption of the new Section is required on or after January 1, 2004, however Compton chose to early adopt effective January 1, 2003.

Compton estimates the undiscounted amount of cash flow required to settle the asset retirement obligation is approximately $135 million. A credit-adjusted risk free rate of 10.6% was used to calculate the carrying value of the asset retirement obligation.

As the result of adopting this Section, all prior periods have been restated. The change results in a decrease in net earnings of $1 million for the year ended December 31, 2003 (2002 - $1 million, 2001 - $1 million). The effect of this change on the December 31, 2003 consolidated balance sheet is an increase in net capital assets of $7 million (2002 - $7 million), recognition of the asset retirement obligation of $17 million (2002

- $17 million), elimination of the site restoration provision of $1 million (2002 - $2 million), decrease in future income taxes of $3 million (2002 - $3 million) and a decrease in consolidated retained earnings of $6 million (2002 - $5 million, 2001 - $5 million).

HEDGE ACCOUNTING

In December 2001, the CICA modified Accounting Guideline 13, "Hedging Relationships" ("AcG-13"). The Guideline establishes certain conditions where hedge accounting may be applied, effective for fiscal years beginning on or after July 1, 2003. Additionally, the CICA's Emerging Issues Committee ("EIC") amended their guidance in EIC 128, "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments," to require that all derivative instruments that do not qualify for hedge accounting or are not designated as hedges, be recorded on the balance sheet with changes in fair value recognized in earnings.

Compton adopted the modified Guideline effective January 1, 2004 and elected not to designate any of its current risk management activities as accounting hedges under AcG-13. The Company will account for all derivatives using the mark-to-market accounting method. The impact on the Company's consolidated financial statements at January 1, 2004 is an increase in liabilities of $11 million and a deferred loss of $11 million which will be recognized as the contracts expire.

IMPAIRMENT TEST

In September 2003, the CICA approved Accounting Guideline 16, "Oil and Gas Accounting – Full Cost." The new Guideline modifies the way the impairment test is performed and requires that costs centers be tested for recoverability using undiscounted future cash flows from proved reserves plus the cost of undeveloped properties. When the carrying amount of the asset is not recoverable, the asset would be written down to its fair value.

The Guideline is effective for fiscal years beginning on or after January 1, 2004; Compton chose to early adopt in the fourth quarter of 2003. There is no impact on the carrying value of the Company's assets as a result of applying the new guideline.

VARIABLE INTEREST ENTITIES

In December 2003, the Financial Accounting Standards Board in the United States issued Interpretation 46 (revised December 2003) "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51" ("FIN 46R"). The standard requires that variable interest entities be consolidated by their primary beneficiary. The standard is effective for the first period ending after December 15, 2003. In Canada, the Accounting Standards Board issued a draft guideline proposing amendments to Accounting Guideline AcG-15, "Consolidation of Variable Interest Entities" which is expected to be substantially in accordance with the United States standard. Once finalized, the amendments would harmonize the guideline with the corresponding United States standard. The amended guideline remains effective for annual and interim periods beginning on or after November 1, 2004.

The Company adopted the provisions of FIN 46R as of December 31, 2003. The effects of adopting FIN 46R on the consolidated financial statements are summarized in Note 4.

IMPACT ON NET INCOME OF CHANGE IN ACCOUNTING POLICIES

The implementation of new accounting polices relating to asset retirement obligations in 2003 resulted in the restatement of previously reported net earnings.

The following table shows the impact of the new accounting policies on net income.

Years ended December 31, ($000s)	2003	2002	2001
(Decrease) in net earnings, related to:			
Stock based compensation	$ (800)	$ –	$ –
Asset retirement obligations	(700)	(500)	(600)
Hedge accounting	–	–	–
Ceiling test	–	–	–
Total impact on net earnings	$ (1,500)	$ (500)	$ (600)

Financial Conditions and Risks

Compton's operations are subject to risks normally associated with the oil and natural gas industry. The Company is exposed to financial risks including commodity prices and expenditure costs shifting due to changes in market conditions. Commodity prices are driven by supply, demand and market forces outside the Company's influence. The Company's product mix is diversified to minimize exposure to any one commodity's price movements. Sales of oil and natural gas are aimed at various markets to avoid undue exposure to any one market. When appropriate, Compton ensures that parental guarantees or letter of credit are in place to minimize the impact in the event of default.

Compton monitors and focuses its expenditures to reflect price and production changes. Compton continuously scrutinizes market conditions and opportunities. From time to time the Company will employ financial instruments to manage exposure related to Canada/U.S. exchange rates and commodity prices.

The Company has commodity and fixed-price contracts outstanding as outlined in the Financial Instruments section of this MD&A. The Company considers longer-term contracts with suppliers, where appropriate, to mitigate shifts in costs resulting from changes in industry and market conditions. Compton has no control over government intervention or taxation levels on the industry.

It is likely that in the future the Company will be required to raise additional capital via debt and/or equity financings in order to fully realize its strategic goals and business plans. Compton's ability to raise additional capital will depend upon a number of factors, such as general economic and market conditions that are beyond its control. If Compton is unable to obtain additional financing or to obtain it on favorable terms, the Company might be required to forego attractive business opportunities. Compton is committed to maintaining a strong balance sheet, combined with a flexible capital expenditure program that can be adjusted to capitalize on acquisition opportunities or reflect a tightening of liquidity sources.

Financial Instruments

From time to time, Compton enters into hedge transactions to manage fluctuations in commodity prices and foreign currency. The Company does not participate in derivative or other financial instruments for trading purposes and commodity price contracts may not exceed 50% of non-contracted production. Management considers an abundance of information from a variety of sources before entering into a financial transaction. The Audit, Finance and Risk Committee of the Board of Directors regularly reviews the Company's hedging strategies and transactions to mitigate this risk.

INTEREST RATE RISK MANAGEMENT

The Company entered into an interest rate swap arrangement upon the closing of its U.S. senior notes offering in May 2002. The arrangement converts fixed rate U.S. dollar denominated debt to floating rate Canadian dollar denominated debt and protects Compton against fluctuations in the Canadian U.S. exchange rate. The terms of the swaps correlate with the terms of the debt agreement and has resulted in an effective interest rate of 7.85% (2002 – 7.65%). At December 31, 2003 there was an unrealized hedge loss of $9 million (2002 - $15 million gain), as calculated on a mark-to-market basis by the issuer of the instrument.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and to a large extent natural gas prices are based upon reference prices denominated in U.S. dollars, while the majority of the Company's expenses are denominated in Canadian dollars. When appropriate, the Company enters into agreements to fix the exchange rate of Canadian dollars to U.S. dollars in order to manage the risk. During the year a gain of $2 million was realized and included in revenue (2002 - $nil; 2001 - $nil). At December 31, 2003, all swaps had expired and the Company has not entered into any arrangements for 2004.

COMMODITY PRICE RISK MANAGEMENT

The Company enters into commodity price contracts to hedge anticipated sales of oil and natural gas production to protect cash flows for its capital expenditure programs. Commodity price risk is actively managed by using costless collars and by balancing physical and financial contracts in terms of volumes, timing of performance and delivery obligations. However, net open positions may exist, or may be established to take advantage of market conditions. Oil and natural gas revenues for the year ended December 31, 2003 include losses of $8 million (2002 – $1 million gain; 2001 - $4 million gain) on these transactions. At December 31, 2003 there was an unrealized gain of $2 million on commodity hedges, as calculated on a mark-to-market basis by the issuer of the instrument.

Hedging transactions in 2004 are as follows:

Commodity	Type	Term	Amount	Average Price	Index
Natural gas	Collars	Jan - Mar '04	30,000 GJ	Cdn.$5.34 - $7.56	AECO
	Collars	Apr - June '04	35,000 GJ	Cdn.$4.96 - $6.59	AECO
	Collars	July - Oct '04	30,000 GJ	Cdn.$5.13 - $6.76	AECO
	Collars	Nov – Dec '04	10,000 GJ	Cdn.$5.38 - $7.18	AECO
Crude oil	Collars	Jan 2003 – Dec 2004	1,500 bbls/d	U.S.$25.83 – $29.37	WTI

As at March 31, 2004, the Company had incurred a realized loss of $1 million and an unrealized mark-to-market loss of $5 million on these commodity hedges.

Selected Quarterly Information

The following tables set out selected quarterly financial information of the Company for the last two fiscal years.

Year ended December 31, 2003 ($000s, except where noted)	Three Months Ended March 31	June 30	Sept 30 (1)	Dec 31	Year Ended Dec 31
Total revenue	$ 92,444	$ 83,305	$ 76,762	$ 82,182	$ 334,693
Cash flow	$ 48,160	$ 39,888	$ 34,220	$ 32,625	$ 154,893
Cash flow/share (basic) *($/share)*	$ 0.41	$ 0.34	$ 0.29	$ 0.28	$ 1.33
Cash flow/share (diluted) *($/share)*	$ 0.39	$ 0.33	$ 0.28	$ 0.27	$ 1.27
Net income	$ 31,894	$ 64,750	$ 10,455	$ 11,781	$ 118,880
Net income/share (basic) *($/share)*	$ 0.27	$ 0.56	$ 0.09	$ 0.10	$ 1.02
Net income/share (diluted) *($/share)*	$ 0.26	$ 0.53	$ 0.09	$ 0.10	$ 0.97
Average production *(boe/d)*	25,853	25,659	24,219	26,484	25,552
Average pricing *($/boe)*	$ 39.73	$ 35.68	$ 34.02	$ 33.28	$ 35.66

(1) Restated for inclusion of Mazeppa Processing Partnership.

Year ended December 31, 2002 ($000s, except where noted)	Three Months Ended March 31	June 30	Sept 30 (1)	Dec 31	Year Ended Dec 31
Total revenue	$ 42,548	$ 54,018	$ 50,889	$ 72,332	$ 219,787
Cash flow	$ 18,393	$ 23,513	$ 19,624	$ 34,542	$ 96,072
Cash flow/share (basic) *($/share)*	$ 0.16	$ 0.21	$ 0.17	$ 0.30	$ 0.85
Cash flow/share (diluted) *($/share)*	$ 0.16	$ 0.20	$ 0.17	$ 0.29	$ 0.81
Net income (1)	$ 3,317	$ 10,872	$ 1,292	$ 2,831	$ 18,312
Net income (1)/share (basic) *($/share)*	$ 0.03	$ 0.10	$ 0.01	$ 0.03	$ 0.16
Net income (1)/share (diluted) *($/share)*	$ 0.03	$ 0.09	$ 0.01	$ 0.02	$ 0.16
Average production *(boe/d)*	24,443	24,737	24,782	26,567	25,137
Average pricing *($/boe)*	$ 19.34	$ 24.00	$ 22.32	$ 29.59	$ 23.95

(1) Restated for changes in accounting policies adopted in 2003. See consolidated financial statements.

In 2003, strong overall commodity prices and the decline of the Company's portion of natural gas production dedicated to aggregators to 16%, resulted in higher realized prices and increased total revenue. Additionally, an unrealized foreign exchange gain on the translation of the Company's U.S. denominated debt in the first and second quarters of 2003 and a recovery of future income taxes in the second quarter due to a reduction in federal and provincial income tax rates on income earned from resource activities, significantly increased quarterly net income when compared to the same quarters in 2002. The consolidation of MPP did not have a material impact on total revenue or net income in 2003.

Revenue in 2002 fluctuated on a quarterly basis largely due to average realized prices. Overall commodity prices rose throughout 2002, however, approximately 35% of Compton's natural gas production was marketed through aggregator contracts. These contracts received a price that was on average $0.94/mcf less than prices received on non-aggregator volumes. Quarterly net income in 2002 followed the trend set by revenue, with the exception of the fourth quarter. An $18 million future tax expense recorded in the fourth quarter decreased net income to $3 million for the three months ended December 31, 2002.

Fourth Quarter 2003

Fourth quarter 2003 production increased approximately 9% from that of the preceding 2003 quarter. This increase resulted from new production being placed on-stream and gas plants shut-in during the third quarter for regularly scheduled maintenance coming back on-stream.

Net income increased by 12% from the third quarter of 2003. Higher net income in the fourth quarter of 2003 resulted from increased production volumes and revenue. The consolidation of MPP did not have a material impact on the fourth quarter results.

Selected Annual Information

Years ended and as at December 31, ($000s)	2003	2002	2001
Total revenue	$ 334,693	$ 219,787	$ 244,970
Net income	$ 118,880	$ 18,312	$ 55,015
Net income/share (basic)	$ 1.02	$ 0.16	$ 0.50
Net income/share (diluted)	$ 0.97	$ 0.16	$ 0.48
Total assets	$ 1,064,320	$ 823,859	$ 700,622
Total long term financial liabilities	$ 213,246	$ 260,634	$ 230,000

Total assets were $1.1 billion at December 31, 2003, an increase of 29% from the prior year, due primarily to a 31% increase in the carrying value of property and equipment. In addition to capital expenditures of $221 million, the carrying value of property and equipment, before accumulated depletion and depreciation, increased by $65 million relating to midstream facilities owned by MPP and an $11 million charge for future asset retirement costs.

Total assets at December 31, 2002 were $824 million, a 19% increase from 2001 largely due to capital spending on exploration and development activities which increased the carrying value of property and equipment.

In May 2002, the Company completed an offering of U.S. $165 million senior notes. The proceeds were used to repay outstanding bank debt and resulted in a net increase in total long term financial liabilities from 2001 to 2002. At December 31, 2003, total long term debt was $213 million, down 18% from 2002 due to a stronger year end Canadian U.S. dollar exchange rate. The amount of the outstanding notes is restated in Canadian dollars using the year end exchange rate.

Trading and Share Statistics

As at April 19, 2004, there were 117,217,353 common shares outstanding.

	2003				Total	
	March 31	June 30	Sept 30	Dec 31	2003	2002
Average daily trading volume *(000s)*	687,068	804,989	654,060	598,300	686,100	324,865
Share price *($/share)*						
High	$ 5.90	$ 6.35	$ 6.35	$ 6.23	$ 6.35	$ 5.35
Low	$ 4.70	$ 4.40	$ 5.48	$ 5.38	$ 4.40	$ 3.20
Close	$ 4.90	$ 5.88	$ 5.70	$ 6.00	$ 6.00	$ 5.09
Market capitalization at December 31 *($000s)*					$ 698,535	$ 591,819
Shares outstanding *(000s)*					116,423	116,271

Further Information

Additional information about Compton, including the Company's Annual Information Form, is available on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com.

MANAGEMENT'S REPORT

To the Shareholders of Compton Petroleum Corporation

The accompanying consolidated financial statements of Compton Petroleum Corporation and all other financial and operating information contained in this Annual Report are the responsibility of Management. The consolidated financial statements have been prepared in accordance with accounting policies detailed in the notes to the consolidated financial statements and in accordance with generally accepted accounting principles in Canada.

The Company's systems of internal control have been designed and maintained to provide reasonable assurance that assets are properly safeguarded and that the financial records are sufficiently well maintained to provide relevant, timely and reliable information to management.

External auditors, appointed by the shareholders, have independently examined the consolidated financial statements. They have performed such tests as they deemed necessary to enable them to express an opinion on these consolidated financial statements.

The Audit, Finance and Risk Committee of the Board of Directors has reviewed these consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit, Finance and Risk Committee.

E.G. Sapieha, C.A.	**N.G. Knecht, C.A.**
President &	Vice President Finance &
Chief Executive Officer	Chief Financial Officer

April 19, 2004

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Compton Petroleum Corporation

We have audited the consolidated balance sheets of Compton Petroleum Corporation as at December 31, 2003 and 2002 and the consolidated statements of earnings, retained earnings and cash flow for each of the years in the three year period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada and the United States of America. These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and cash flow for each of the years in the three year period ended December 31, 2003 in accordance with accounting principles generally accepted in Canada.

Grant Thornton LLP

Grant Thornton LLP
Chartered Accountants
Calgary, Alberta
Canada

April 19, 2004

Comments by Auditor for U.S. Readers on Canada-U.S. Reporting Differences

In the United States of America, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the changes described in Note 2 to the consolidated financial statements. Also, in the United States of America, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a restatement of the Company's historical financial statements, such as correction of an error in application of accounting principle described in Note 18(f) to the consolidated financial statements. Our report to the shareholders dated April 19, 2004 is expressed in accordance with Canadian reporting standards, which do not require a reference to such a change in accounting principles and correction of an error in the Auditors' Report, when the change is properly accounted for and adequately disclosed in the consolidated financial statements.

Grant Thornton LLP

Grant Thornton LLP
Chartered Accountants
Calgary, Alberta
Canada

April 19, 2004

CONSOLIDATED BALANCE SHEETS

As at December 31		2003	2002
(thousands of dollars)			*(restated Note 2)*
Assets			
Current			
Cash		$ 15,548	$ 14,725
Accounts receivable and other		97,283	80,689
		112,831	95,414
Deferred financing charges		11,432	13,444
Property and equipment	*(Note 5)*	940,057	715,001
		$ 1,064,320	$ 823,859
Liabilities			
Current			
Bank debt	*(Note 6)*	$ 164,500	$ 40,000
Accounts payable		85,730	62,059
Taxes payable		2,757	1,216
		252,987	103,275
Senior term notes	*(Note 7)*	213,246	260,634
Asset retirement obligations	*(Note 8)*	17,329	17,335
Other liabilities	*(Note 12)*	155	126
Future income taxes	*(Note 13)*	223,807	202,371
		707,524	583,741
Non-controlling interest	*(Note 4)*	(110)	–
Shareholders' equity			
Capital stock	*(Note 9)*	131,577	128,079
Contributed surplus	*(Note 2c)*	760	–
Retained earnings		224,569	112,039
		356,906	240,118
		$ 1,064,320	$ 823,859

Commitments and contingencies *(Note 16)*
Subsequent event *(Note 17)*

On behalf of the Board

Mel Belich
Director

Irvine Koop
Director

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF EARNINGS

Years ended December 31,		2003	2002	2001
(thousands of dollars, except per share data)			*(restated Note 2)*	*(restated Note 2)*
Revenue				
Oil and natural gas revenues		$ 334,693	$ 219,787	$ 244,970
Royalties		(82,566)	(47,497)	(55,919)
		252,127	172,290	189,051
Expenses				
Operating		51,988	45,546	40,222
General and administrative		12,206	9,845	6,582
Interest, net		29,230	20,130	12,863
Depletion and depreciation		61,749	55,473	50,283
Accretion of asset retirement obligations	*(Note 8)*	1,436	1,241	1,085
Foreign exchange (gain) loss		(47,368)	1,583	–
Stock-based compensation	*(Note 10)*	793	190	(280)
		110,034	134,008	110,755
Earnings before taxes and non-controlling interest		142,093	38,282	78,296
Taxes	*(Note 13)*			
Current		3,282	1,428	1,330
Future		20,041	18,542	21,951
		23,323	19,970	23,281
Earnings before non-controlling interest		118,770	18,312	55,015
Non-controlling interest	*(Note 4)*	(110)	–	–
Net earnings		$ 118,880	$ 18,312	$ 55,015
Earnings per share	*(Note 11)*			
Basic		$ 1.02	$ 0.16	$ 0.50
Diluted		$ 0.97	$ 0.16	$ 0.48

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Years ended December 31,		2003	2002	2001
(thousands of dollars)			*(restated Note 2)*	*(restated Note 2)*
Retained earnings, as previously reported		$ 117,720	$ 101,288	$ 63,324
Change in accounting policies				
Asset retirement obligations	*(Note 2a)*	(5,681)	(5,195)	(4,574)
Stock-based compensation	*(Note 2c)*	–	–	(3,585)
Retained earnings, as restated		112,039	96,093	55,165
Net earnings		118,880	18,312	55,015
Premium on redemption of shares	*(Note 9b)*	(6,350)	(2,366)	(14,087)
Retained earnings, end of year		$ 224,569	$ 112,039	$ 96,093

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

Years ended December 31,		2003	2002	2001
(thousands of dollars)			*(restated Note 2)*	*(restated Note 2)*
Operating activities				
Net earnings		$ 118,880	$ 18,312	$ 55,015
Amortization of deferred charges		2,144	1,367	–
Depletion and depreciation		61,749	55,473	50,283
Accretion of asset retirement obligations		1,436	1,241	1,085
Unrealized foreign exchange (gain) loss	*(Note 7)*	(47,388)	1,583	–
Stock-based compensation		760	–	–
Future income taxes		20,041	18,542	21,951
Pension expense		64	–	–
Asset retirement expenditures		(2,683)	(446)	(473)
Non-controlling interest		(110)	–	–
Cash flow from operations		154,893	96,072	127,861
Change in non-cash working capital	*(Note 15)*	1,354	(4,843)	(7,266)
		156,247	91,229	120,595
Financing activities				
Issuance (repayment) of bank debt		124,500	(190,000)	36,304
Capital lease obligations		(36)	(323)	(38)
Issuance of senior notes		–	259,050	–
Deferred financing charges		(128)	(14,810)	–
Proceeds from share issuances, net		6,400	18,177	41,558
Redemption of common shares		(7,942)	(3,026)	(17,774)
Change in non-cash working capital	*(Note 15)*	(1,387)	3,514	–
		121,407	72,582	60,050
Investing activities				
Property and equipment additions		(222,055)	(127,993)	(147,993)
Corporate acquisitions	*(Note 3)*	–	–	(29,669)
Property acquisitions		(65,622)	(44,857)	(18,974)
Property dispositions		2,194	17,700	8,731
Change in non-cash working capital	*(Note 15)*	8,652	1,012	12,312
		(276,831)	(154,138)	(175,593)
Change in cash		823	9,673	5,052
Cash, beginning of year		14,725	5,052	–
Cash, end of year		$ 15,548	$ 14,725	$ 5,052

See accompanying notes to the consolidated financial statements.

(Tabular amounts in thousands of dollars, unless otherwise stated)

December 31, 2003

1. SIGNIFICANT ACCOUNTING POLICIES

The Company is engaged primarily in the exploration for and production of petroleum and natural gas reserves in the Western Canadian Sedimentary Basin.

a) Basis of presentation

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada within the framework of the accounting policies summarized below. Information prepared in accordance with accounting principles generally accepted in the United States is included in Note 18.

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries from their respective dates of acquisition. The consolidated financial statements also include the accounts of Mazeppa Processing Partnership in accordance with the accounting policy outlined in Note 2(e).

b) Measurement uncertainty

The timely preparation of financial statements requires that Management make estimates and assumptions and use judgment regarding assets, liabilities, revenues and expenses. Such estimates relate primarily to transactions and events that have not settled as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depletion and depreciation, asset retirement obligations and amounts used in impairment test calculations are based upon estimates of petroleum and natural gas reserves and future costs to develop those reserves. By their nature, these estimates of reserves, costs and related future cash flows are subject to uncertainty, and the impact on the consolidated financial statements of future periods could be material.

c) Property and equipment

i) CAPITALIZED COSTS

The Company follows the full cost method of accounting for its petroleum and natural gas operations as determined by the Canadian Institute of Chartered Accounts ("CICA"), Accounting Guideline 16 ("AcG-16"). Under this method all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Costs include lease acquisition costs, geological and geophysical expenses, costs of drilling both producing and non-producing wells, production facilities and asset retirement costs. Proceeds from the sale of properties are applied against capitalized costs, without any gain or loss being realized, unless such sale would significantly alter the rate of depletion and depreciation.

ii) DEPLETION AND DEPRECIATION

Depletion and depreciation of property and equipment is provided using the unit-of-production method based upon estimated proved petroleum and natural gas reserves. The costs of significant undeveloped properties are excluded from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties or impairment has occurred. Estimated future costs to be incurred in developing proved reserves are included in costs subject to depletion. For depletion and depreciation purposes, relative volumes of natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Depreciation of certain midstream facilities are provided for on a straight line basis over 30 years.

Depreciation of office equipment is provided for on a declining-balance basis at 20% per annum.

iii) IMPAIRMENT TEST

At each reporting period the Company performs an impairment test to determine the recoverability of capitalized costs associated with reserves. An impairment loss is recognized in net earnings when the carrying amount of a cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves plus the costs of unproved properties. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of the fair value of proved and probable reserves and the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

iv) ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of estimated asset retirement obligations on the consolidated balance sheet when a reasonable estimate of fair value can be made. Asset retirement obligations include those for which a company faces a legal obligation to retire tangible long-lived assets such as well sites, pipelines and facilities. Increases in the asset retirement obligations resulting from the passage of time are recorded as accretion to the asset retirement obligations in the consolidated statement of earnings. Actual expenditures incurred are charged against the accumulated obligations.

The asset retirement cost, equal to the estimated fair value of the retirement obligations, is capitalized as part of the cost of the related long-lived asset. Asset retirement costs are amortized using the unit-of-production method and are included in depletion and depreciation in the consolidated statement of earnings.

d) Financial instruments

Financial instruments consist mainly of accounts receivable and other, accounts payable and long-term debt. There are no significant differences between the carrying value of these financial instruments and their estimated fair value except as disclosed in Note 14(e).

The Company uses financial instruments for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates, as described in Note 14. Hedge accounting is used when there is a high degree of correlation between price movements in the financial instrument and the item designated as being hedged. Gains and losses are recognized in the same period as the hedged item. If correlation ceases, hedge accounting is terminated and future changes in the market value of the financial instrument are recognized as gains or losses in the period.

e) Joint operations

Certain petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

f) Flow-through shares

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. The liability for future income taxes is increased and capital stock is reduced by the estimated tax benefits transferred to shareholders at the time the resource expenditure deductions are renounced.

g) Earnings per share amounts

Basic net earnings per common share is determined by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed by giving effect to the potential dilution that would occur if stock options were exercised. The treasury stock method is used to determine the dilutive effect of stock options. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market rate for the period.

h) Income taxes

Income taxes are recorded using the liability method of accounting. Future income taxes are calculated based on the difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Changes in current income tax rates are reflected in the liability for future income taxes in the period the change occurs.

i) Revenue recognition

Revenue associated with the production and sales of crude oil, natural gas and natural gas liquids owned by the Company are recognized when title passes from the Company to its customer.

Revenue associated with the processing of natural gas and natural gas liquids are recognized in earnings in the same period as when the products are shipped and the purchaser has taken possession of the commodity. Other revenue is recognized in the period that the service is provided to the customer.

j) Stock-based compensation plan

The Company has a stock-based compensation plan which includes stock options and an employee stock savings plan.

The Company uses the fair-value method of accounting for stock options granted to employees and directors after January 1, 2003. Compensation costs are recognized over the vesting period. Fair values are determined using the Black-Scholes option pricing model. The Company used the intrinsic value method of accounting for stock options granted to employees before January 1, 2003.

The Company matches employee contributions to the stock savings plan and these cash payments are recorded as compensation expense.

k) Deferred financing charges

Financing costs related to the issuance of the senior term notes have been deferred and are amortized over the term of the respective senior term notes on a straight-line basis.

l) Foreign currency translation

Long-term debt payable in U.S. dollars is translated into Canadian dollars at the period-end exchange rate, with any resulting adjustment recorded in the consolidated statement of earnings.

m) Dividend policy

The Company has neither declared nor paid any dividends on its common shares. The Company intends to retain its earnings to finance growth and expand its operations and does not anticipate paying any dividends on its common shares in the foreseeable future.

n) Defined benefit pension plan

The Company accrues for its obligations under its defined benefit pension plan and the related costs, net of plan assets. The cost of the pension is actuarially determined using the projected benefit method based on length of service and reflects Management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of any significant actuarial gains or losses. Actuarial evaluations are required every three years, the most recent being January 1, 2003.

The Company has early adopted the amendments made to note disclosure requirements in the CICA Handbook section 3461, "Employee Future Benefits".

o) Comparative amounts

Certain comparative amounts have been reclassified to conform with current year presentation.

2. CHANGES IN ACCOUNTING POLICIES

a) Asset retirement obligations

During the fourth quarter of 2003, the Company retroactively early adopted the Canadian accounting standard as outlined in CICA Handbook section 3110, "Asset Retirement Obligations". The Company previously estimated costs of site restoration and abandonment and recognized them in earnings on a unit-of-production basis with a corresponding liability on the balance sheet. With the adoption of the new accounting standard, all prior periods have been restated. The following table summarizes the effects of this change in accounting policy.

	Change, increase (decrease)					
Years ended December 31, (millions)		2003		2002		2001
Assets						
Property and equipment	$	7.1	$	6.6	$	6.6
Liabilities						
Asset retirement obligations	$	17.3	$	17.3	$	16.0
Future income taxes	$	(3.1)	$	(2.8)	$	(2.6)
Future site restoration	$	(0.7)	$	(2.2)	$	(1.6)
Shareholders' equity						
Retained earnings	$	(5.7)	$	(5.2)	$	(4.6)
Net earnings	$	(0.7)	$	(0.5)	$	(0.6)

Earnings per share, both on a basic and diluted basis, are reduced by less than $0.01 per share in each of the three years.

b) Full cost accounting

During the fourth quarter of 2003 the Company early adopted CICA Accounting Guideline 16 "Oil and Gas Accounting – Full Cost". The new guideline modifies the way the impairment test is performed and requires costs centres be tested for recoverability using undiscounted future cash flows from proved reserves plus the cost of undeveloped properties. When the carrying amount of the asset is not recoverable, the asset would be written down to its fair value. Fair value is determined to be discounted cash flow plus undeveloped properties. Discounted cash flow is calculated using a present value technique that incorporates proved plus probable reserves, prices that are consistent with those used by the Company in developing other corporate information and a risk free interest rate.

There is no impact on the carrying value of the Company's assets as a result of applying the new guideline.

c) Stock-based compensation

During the fourth quarter of 2003, the Company early adopted the new Canadian accounting standard as outlined in CICA Handbook section 3870, "Stock-based Compensation and Other Stock-based Payments". The new section requires the use of the fair-value method of accounting for the stock options granted to employees and directors. As allowed by section 3870, this policy has been adopted prospectively and prior years have not been restated. The Company records a stock based compensation expense in the consolidated statement of earnings for all options granted on or after January 1, 2003, with a corresponding increase to contributed surplus. Compensation expense for options granted during 2003 is based on the estimated fair values at the time of the grant and the expense is recognized over the vesting period of the option. The Company recognized $0.8 million of compensation expense and contributed surplus for options granted during 2003. For options granted from January 1, 2001 to December 31, 2002, the Company continues to disclose the pro-forma earnings impact of related stock-based compensation expense (see Note 10(a)).

During the fourth quarter of 2001, the Company early adopted the recommendations of the CICA with respect to accounting for stock-based compensation. The Company adopted this accounting policy retroactively, without restating the consolidated financial statements of prior periods. Effective January 1, 2001, the Company recorded a reduction in retained earnings of $3.6 million, an increase in accounts payable of $6.2 million and a decrease in future income tax liability of $2.6 million.

d) Impairment of long-lived assets

During the fourth quarter of 2003, the Company early adopted the standards outlined in the CICA Handbook section 3063, "Impairment of Long-Lived Assets" which establishes standards for the recognition, measurement and disclosure of any impairment of long-lived assets comprised of MPP assets and office equipment. An impairment is recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The Company estimates fair value based upon current prices for similar assets. The accounting policy has been adopted prospectively and has no impact on these consolidated financial statements.

e) Variable interest entities

In December 2003, the Financial Accounting Standards Board ("FASB") in the United States issued Interpretation 46 (revised December 2003) "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51" ("FIN 46R"). The standard requires that variable interest entities be consolidated by their primary beneficiary. The standard is effective for the first period ending after December 15, 2003. In Canada, the Accounting Standards Board ("AcSB") issued a draft guideline proposing amendments to Accounting Guideline AcG-15, "Consolidation of Variable Interest Entities" which is expected to be substantially in accordance with the United States standard. Once finalized, the amendments would harmonize the guideline with the corresponding United States standard. The amended guideline remains effective for annual and interim periods beginning on or after November 1, 2004.

The Company adopted the provisions of FIN 46R as of December 31, 2003. The effects of adopting FIN 46R on the consolidated financial statements are summarized in Note 4.

f) Recently issued accounting pronouncements

During 2003, the CICA modified Accounting Guideline 13 ("AcG-13") "Hedging Relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. In addition, the CICA amended EIC 128, "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments" to require that all derivative instruments that do not qualify for hedge accounting or are not designated as hedges, be recorded in the balance sheet as either an asset or liability with changes in fair value recognized in earnings. For 2004, the Company has elected not to designate any of its current risk management activities as accounting hedges under AcG-13 and will account for all derivatives using the mark-to-market accounting method. The impact on the Company's financial statements at January 1, 2004 is an increase in liabilities of $10.9 million and a deferred loss of $10.9 million which will be recognized as these contracts expire.

3. ACQUISITION

Effective July 16, 2001, the Company acquired all of the issued and outstanding shares of Hornet Energy Ltd. (Hornet), a public company involved in the exploration, development and production of oil and natural gas primarily in southern Alberta. The acquisition has been accounted for by the purchase method of accounting and the consolidated financial statements include the results of operations from date of acquisition. The fair value of the assets acquired is as follows:

As at July 16,		2001
Net assets acquired		
Petroleum and natural gas properties	$	54,276
Future income taxes		(12,236)
		42,040
Working capital deficiency		(2,051)
Long-term debt		(10,320)
	$	29,669
Consideration		
Cash	$	29,134
Transaction costs		535
	$	29,669

The following table reflects unaudited pro-forma combined results of operations of the Company and the above acquisition on the basis that the acquisition had taken place at the beginning of the fiscal years presented:

Year ended December 31		2001
Revenue, net of royalties	$	195,593
Net earnings		51,490
Earnings per share		
Basic	$	0.47
Diluted		0.45

4. SEGMENTED INFORMATION

In June of 2003, Mazeppa Processing Partnership ("MPP"), a limited partnership organized under the laws of the province of Alberta, acquired certain midstream assets from an independent third party. The assets consist of major natural gas gathering and processing facilities in southern Alberta. The Company has minimal equity ownership in MPP. However, in its capacity as general partner, the Company has control of MPP and manages the activities of the partnership and processes a significant portion of its production in southern Alberta through the facilities. Therefore the Company is considered to be the primary beneficiary of MPP's operations and the consolidated financial statements of the Company include the accounts of MPP in accordance with the accounting policy outlined in Note 2(e).

The operations of MPP are considered to be a business segment separate and distinct from the Company's exploration, exploitation, development and production activities ("E&P activities"). Information relating to the two business segments is summarized below and inter-company transactions are eliminated on consolidation as indicated.

Year ended December 31, 2003	E&P activities	MPP	Inter-company	Total
Oil and natural gas revenues	$ 332,759	$ 8,114	$ (6,180)	$ 334,693
Royalties	(82,566)	–	–	(82,566)
	250,193	8,114	(6,180)	252,127
Operating	52,733	5,299	(6,044)	51,988
General and administrative	11,992	350	(136)	12,206
Interest, net	27,788	1,442	–	29,230
Depletion and depreciation	60,631	1,118	–	61,749
Accretion of asset retirement obligations	1,421	15	–	1,436
Foreign exchange (gain)	(47,368)	–	–	(47,368)
Stock-based compensation	793	–	–	793
	107,990	8,224	(6,180)	110,034
Earnings before taxes and non-controlling interest	142,203	(110)	–	142,093
Taxes	23,323	–	–	23,323
Non-controlling interest	–	–	(110)	(110)
Net earnings (loss)	$ 118,880	$ (110)	$ 110	$ 118,880

Earnings (losses) from the operations of MPP are attributable to the Limited Partner and are charged to non-controlling interest on the consolidated balance sheet.

CAPITAL EXPENDITURES

Year ended December 31, 2003	E&P activities	MPP	Total
Property and equipment additions	$ 208,392	$ 13,663	$ 222,055
Property acquisitions	13,418	52,204	65,622
Property dispositions	(2,194)	–	(2,194)
	$ 219,616	$ 65,867	$ 285,483

PROPERTY AND EQUIPMENT AND TOTAL ASSETS

As at December 31, 2003	Property and equipment	Total assets
E&P activities	$ 874,982	$ 1,062,228
MPP	65,075	70,223
Inter-company elimination	–	(68,131)
	$ 940,057	$ 1,064,320

The Company has advanced funds to MPP necessary to acquire the midstream assets, expand the facilities and fund ongoing operations. The inter-company elimination of total assets noted above relates to an inter-company receivable/payable in respect to these amounts. MPP is currently in the process of securing alternative funding, the proceeds of which will be used to repay funds advanced by the Company.

5. PROPERTY AND EQUIPMENT

	2003			2002		
As at December 31,	Cost	Accumulated depletion and depreciation	Net	Cost	Accumulated depletion and depreciation	Net
Exploration and development costs	$ 931,970	$ (212,223)	$ 719,747	$ 758,716	$ (158,581)	$ 600,135
Production equipment and processing facilities	231,918	(21,411)	210,507	120,537	(14,725)	105,812
Future asset retirement costs	10,557	(3,422)	7,135	9,315	(2,729)	6,586
Office equipment	5,143	(2,475)	2,668	4,216	(1,748)	2,468
	$1,179,588	$ (239,531)	$ 940,057	$ 892,784	$ (177,783)	$ 715,001

Employee salaries of $3.3 million (2002 – $2.7 million; 2001 – $2.5 million) directly related to exploration and development activities are capitalized. No other general and administrative expenses are capitalized.

Future capital expenditures of $62.4 million (2002 - $37.5 million; 2001 - $33.0 million), as estimated by independent engineers, relating to the development of proved reserves have been included in costs subject to depletion. Undeveloped properties with a cost at December 31, 2003 of $161.9 million (2002 - $155.0 million; 2001 - $161.0 million), included in exploration and development costs, have not been subject to depletion.

The prices used in the impairment test evaluation of the Company's natural gas, crude oil and natural gas liquids reserves were:

As at December 31, 2003	Natural gas $ per mcf	Oil $ per bbl	NGL $ per bbl
2004	$ 6.13	$ 37.99	$ 31.54
2005	$ 5.48	$ 34.24	$ 26.69
2006	$ 4.90	$ 32.87	$ 25.16
2007	$ 5.03	$ 33.37	$ 24.61
2008	$ 5.12	$ 33.87	$ 25.40
% increase thereafter	1.5	1.5	1.5

6. CREDIT FACILITIES

As at December 31,	2003	2002
Authorized		
Extendible revolving credit facility	$ 175,000	$ 158,000
Working capital facility	10,000	10,000
Total	$ 185,000	$ 168,000
Utilized	$ 164,500	$ 40,000

As of July 7, 2003, the Company had a net borrowing base of $240.0 million as determined by the Company's Canadian banking syndicate and arranged authorized syndicated senior credit facilities, in the amount of $185.0 million (2002 - $168.0 million). The senior credit facilities consist of a $175.0 million (2002 - $158.0 million) extendible revolving credit facility and a $10 million (2002 - $10 million) working capital facility. Advances under the

facilities can be drawn in either Canadian or U.S. funds. The facilities bear interest at the lenders' prime lending rate or at the Bankers' Acceptance rate or LIBOR plus a margin, currently set at 0.70%, 1.70% and 1.70%, respectively. Margins are determined based on the ratio of total consolidated debt to cash flow. Subsequent to December 31, 2003, the authorized credit facilities were increased to $215.0 million. These facilities mature on July 7, 2004.

The credit facilities are secured by a first fixed and floating charge debenture in the amount of $325.0 million covering all the Company's assets and undertakings.

7. SENIOR TERM NOTES

As at December 31,	2003	2002
Senior term notes (U.S. $165.0 million)		
Proceeds on issuance	$ 259,051	$ 259,051
Unrealized foreign exchange (gain) loss	(45,805)	1,583
	$ 213,246	$ 260,634

On May 8, 2002, the Company completed an offering of U.S. $165.0 million senior notes bearing interest at 9.9% with principal repayable on May 15, 2009. Interest is payable on May 15 and November 15 of each year, beginning on November 15, 2002. These senior notes are unsecured and are subordinated to the Company's bank credit facilities.

Concurrent with the closing of the senior notes offering, the Company entered into interest rate swap arrangements with its banking syndicate whereby interest paid by the Company on the U.S. $165.0 million principal amount is based upon the 90 day Bankers' Acceptance rate plus 4.85%. This arrangement resulted in an effective interest rate of 7.85% during the year ended December 31, 2003 (2002 – 7.65%).

Interest incurred on senior term notes was $20.3 million for year ended December 31, 2003 (2002 - $12.9 million).

8. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligations associated with the retirement of oil and natural gas assets:

As at December 31,	2003	2002
Asset retirement obligations, beginning of year	$ 17,335	$ 16,010
Liabilities incurred	1,241	530
Liabilities settled	(2,683)	(446)
Accretion expense	1,436	1,241
Asset retirement obligations, end of year	$ 17,329	$ 17,335

The total undiscounted amount of estimated cash flows required to settle the obligations is $135.1 million (2002 - $103.9 million), which has been discounted using a credit-adjusted risk free rate of 10.6%. The majority of these obligations are not expected to be settled for years, or decades, in the future and will be funded from general Company resources at the time of retirement and removal.

9. CAPITAL STOCK

a) Authorized

Unlimited number of common shares

Unlimited number of preferred shares, issuable in series

b) Issued and outstanding

	2003		2002		2001	
As at December 31,	Number of shares (000's)	Amount	Number of shares (000's)	Amount	Number of shares (000's)	Amount
Common shares outstanding, beginning of year	116,271	$ 128,079	113,105	$ 116,572	108,784	$ 94,472
Shares issued for cash, net	587	2,712	3,085	9,711	7,346	22,964
Shares issued for property	15	81	350	1,225	242	1,285
Shares issued for cash on exercise of warrants	–	–	–	–	625	1,095
Shares issued under option plan	913	2,296	527	1,397	314	443
Shares repurchased	(1,363)	(1,591)	(796)	(826)	(4,206)	(3,687)
Common shares outstanding, end of year	116,423	$ 131,577	116,271	$ 128,079	113,105	$ 116,572

Common shares issued for cash were issued on a flow-through basis for income tax purposes. Under the terms of the current year flow-through agreement, the Company is required to expend $4.2 million on qualifying oil and natural gas expenditures prior to December 31, 2004, none of which has been incurred as of December 31, 2003.

Effective March 10, 2003, the Company received approval from the Toronto Stock Exchange for a Normal Course Issuer Bid (the "Bid"). Under the Bid, the Company could purchase for cancellation up to 5,000,000 of its common shares, representing 4.3% of the 116,564,587 common shares outstanding as of March 4, 2003. The Bid expired on March 10, 2004 and was subsequently renewed.

During the year, the Company purchased for cancellation 1,363,401 common shares at an average price of $5.83 per share (2002 – 796,200 shares at an average price of $3.80 per share; 2001 – 4,206,000 shares at an average price of $4.23 per share), pursuant to a normal course issuer bid. The excess of the purchase price over book value has been charged to retained earnings.

c) Shareholder rights plan

The Company has a shareholder rights plan to ensure all shareholders are treated fairly in the event of a take-over offer or other acquisition of control of the Company.

Pursuant to the Plan, the Board of Directors authorized and declared the distribution of one Right in respect of each common share outstanding. In the event that an acquisition of 20% or more of the Company's shares is completed and the acquisition is not a permitted bid, as defined by the Plan, each Right will permit the holder to acquire, at the exercise price of $50.00, such number of common shares as have a market value equal to twice the exercise price.

10. STOCK-BASED COMPENSATION PLANS

a) Stock option plan

The Company has a stock option plan, for directors, officers and employees. The exercise price of each option equals the closing price of the Company's common shares on the Toronto Stock Exchange on the trading day immediately preceding the date on which the option is granted. Options granted under the plan before June 1, 2003 are generally fully exercisable after four years and expire ten years after the grant date. Options granted under the plan after June 1, 2003 are generally fully exercisable after four years and expire five years after the grant date.

The following tables summarize the information relating to stock options:

	2003		2002	
As at December 31,	Stock options	Weighted average exercise price	Stock options	Weighted average exercise price
Outstanding, beginning of year	10,356,528	$ 2.21	9,829,334	$ 2.03
Granted	1,503,100	$ 5.18	1,669,570	$ 4.00
Exercised	(912,621)	$ 2.52	(526,506)	$ 2.65
Forfeited	(275,100)	$ 4.63	(615,870)	$ 3.83
Outstanding, end of year	10,671,907	$ 2.54	10,356,528	$ 2.21
Exercisable, end of year	7,762,977	$ 1.77	7,691,288	$ 1.63

The range of exercise prices of stock options outstanding and exercisable is as follows:

	Outstanding Options			Exercisable Options	
As at December 31, 2003 Range of exercise prices	Number of options outstanding	Weighted average remaining contractual life (years)	Weighted average exercise price	Number of options outstanding	Weighted average exercise price
$0.60 - $1.25	4,070,000	2.91	$ 0.75	4,070,000	$ 0.75
$1.45 - $2.30	1,506,667	5.79	$ 1.94	1,506,667	$ 1.94
$2.98 - $3.50	1,115,315	6.08	$ 3.03	1,040,815	$ 3.03
$3.80 - $4.60	2,814,325	7.97	$ 4.07	1,144,870	$ 4.05
$4.75 - $6.17	1,165,600	6.84	$ 5.39	625	$ 4.85
	10,671,907		$ 2.54	7,762,977	$ 1.77

As described in Note 2(c), the Company recorded stock-based compensation expense in the consolidated statement of earnings, for stock options granted after January 1, 2003 to employees and directors, using the fair-value method. Options granted prior to January 1, 2003 are accounted for using the intrinsic value method. If the Company had applied the fair-value method to options granted prior to 2003 consistent with methodology prescribed by the CICA Handbook section 3870, the Company's pro-forma net earnings and net earnings per share would have been as indicated below:

Years ended December 31,		2003		2002		2001
Net earnings						
As reported	$	118,880	$	18,312	$	55,015
Less fair value of stock options		(2,317)		(3,317)		(3,618)
Pro-forma	$	116,563	$	14,995	$	51,397
Net earnings per common share – basic						
As reported	$	1.02	$	0.16	$	0.50
Pro-forma	$	1.00	$	0.13	$	0.47
Net earnings per common share – diluted						
As reported	$	0.97	$	0.16	$	0.48
Pro-forma	$	0.95	$	0.13	$	0.45

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

Years ended December 31,		2003		2002		2001
Weighted average fair value of options granted	$	3.01	$	3.00	$	2.52
Risk-free interest rate		4.3%		5.2%		5.4%
Expected lives (years)		6.1		10.0		10.0
Expected volatility		56.0%		62.5%		53.8%

b) Share appreciation rights plan

At the beginning of 2001, the Company had a share appreciation rights plan, the financial statement effects of which were determined not to be significant to the consolidated financial statements due to the amount vested. During 2001, this plan was cancelled and replaced by a fixed option plan with a variable component.

As a result, a certain number of outstanding fixed options included in the Company's stock option plan have a variable compensation cost to them. As at December 31, 2001, approximately 2.4 million of the outstanding fixed options total of 9.8 million were granted as a result of the aforementioned cancelled share appreciation rights plan. These fixed options, with a variable component, were granted in two tranches: 1.7 million at a fixed option exercise price of $3.02 per option share and 0.7 million at a fixed option exercise price of $4.00 per option share. Attached to these fixed options is a variable compensation component that enables the holder of such fixed option to receive a cash payment from the Company upon exercise of the fixed option. This cash payment varies with each fixed option holder, and is based on the difference between the lesser of the market price of the Company's common shares on the date the fixed option is exercised or the fixed option exercise price, and a stated compensation price for each respective option holder. Under this structure, the maximum variable compensation cash payment is the respective fixed option exercise price.

Handbook section 3870 requires recognition of compensation costs with respect to changes in the intrinsic value for the variable component of fixed options. During the year ended December 31, 2003, the Company recorded a compensation expense of $33 thousand related to the outstanding variable component of these options (2002 - $190 thousand; 2001 - $280 thousand recovery). The liability related to the variable component of these options amounts to $2.4 million, which is included in accounts payable as at December 31, 2003 (2002 - $3.2 million).

11. PER SHARE AMOUNTS

The following table summarizes the common shares used in calculating net earnings per common share:

As at December 31,	2003	2002	2001
Weighted average common shares outstanding – basic	**116,267**	113,428	109,881
Effect of stock options	**5,856**	4,572	4,963
Weighted average common shares outstanding – diluted	**122,123**	118,000	114,844

In calculating diluted earnings per common share for the year ended December 31, 2003, the Company excluded 615,100 options (2002 – 2,193,662; 2001 – 892,500), as the exercise price was greater than the average market price of its common shares in those years.

12. DEFINED BENEFIT PENSION PLAN

The Company does not have a pension plan for its employees. MPP assumed a defined benefit pension plan providing pension benefits to substantially all of its employees. Information about this defined post-retirement benefit plan is as outlined below:

As at December 31,		2003
Accrued benefit obligation, beginning of period	$	–
Plan acquisition		5,068
Current service cost		111
Interest cost		173
Benefits paid		(41)
Contributions		20
Accrued benefit obligation, end of year	$	5,331
Fair value of plan assets, beginning of period	$	–
Plan acquisition		4,031
Actual return on plan assets		374
Employer contributions		104
Employee contributions		20
Benefits paid		(41)
Fair value of plan assets, end of year	$	4,488
Funded status – plan assets less than benefit obligation	$	843
Unamortized net actuarial gain		221
Unamortized past service cost		(1,000)
Accrued benefit liability, included in other liabilities	$	64

The weighted average assumptions used to determine benefit obligations and periodic expense are as follows:

As at December 31,	2003
Discount rate	6.3%
Expected long-term rate of return on plan assets	7.0%
Rate of compensation increase	4.0%
Average remaining service period of covered employees	15 years

Pension expense, included in MPP operating costs is as follows:

For period ending December 31,		2003
Current service cost	$	111
Interest on accrued benefit obligation		173
Interest on assets		(152)
Amortization of past service cost		37
Pension expense	$	169

MPP expects to contribute $368 thousand to the plan in 2004. Contributions by the participants to the pension plan were $224 thousand for the year ended December 31, 2003.

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The objective of the asset allocation policy is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effects on both contribution requirements and pension expense. The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investments, credit rating categories and foreign currency exposure.

The pension plan asset allocation is as follows:

	Target Allocation %		% of
As at December 31, 2003	Normal	Range	Plan Assets
Domestic equity	40	25-55	37
Foreign equity	20	10-25	25
Fixed income	40	25-55	38
Short term	–	0-20	–
Total	100		100

13. INCOME TAXES

a) The following table reconciles income taxes calculated at the Canadian statutory rate with actual income taxes:

Years ended December 31,		2003		2002		2001
Net earnings before tax	$	142,093	$	38,282	$	78,296
Canadian statutory rate		40.6%		42.1%		42.6%
Expected income taxes	$	57,690	$	16,117	$	33,354
Effect on taxes resulting from:						
Non-deductible crown charges		23,922		17,103		18,357
Resource allowance		(16,485)		(14,471)		(22,984)
Large corporations tax		2,497		1,428		1,330
Statutory tax rate reductions		(37,130)		(1,340)		(7,400)
Non-taxable portion of foreign exchange (gain) loss		(8,202)		334		–
Other		1,031		799		624
Provision for income taxes	$	23,323	$	19,970	$	23,281
Current [1]	$	3,282	$	1,428	$	1,330
Future		20,041		18,542		21,951
	$	23,323	$	19,970	$	23,281

(1) Current taxes include the federal tax on large corporations.

During the second quarter of 2003, federal and provincial tax rate reductions were substantively enacted for purposes of accounting principles generally accepted in Canada. The Canadian federal government introduced legislation to reduce the corporate income tax rate on resource income from 28.0% to 21.0% to be phased in over a five year period starting January 1, 2003. The legislation also eliminates the 25.0% resource allowance and provides for the deductibility of crown royalties paid. The Government of Alberta introduced legislation to reduce its corporate income tax rate from 13.0% to 12.5% effective April 1, 2003. The effect of these changes was recognized during the second quarter of 2003 resulting in a future income tax expense recovery of $37.1 million.

b) The net liability for future income taxes is comprised of:

As at December 31,	2003	2002
Future income tax liabilities		
Property and equipment in excess of tax values	$ 169,855	$ 181,944
Timing of partnership items	62,975	34,494
Foreign exchange gain on long-term debt	7,934	–
Future income tax assets		
Attributed Canadian royalty income	(9,667)	(5,175)
Asset retirement obligations	(6,024)	(5,736)
Non-capital losses carried forward	(789)	(1,360)
Foreign exchange loss on long-term debt	–	(334)
Other	(477)	(1,462)
Net future income tax liability	$ 223,807	$ 202,371

14. FINANCIAL INSTRUMENTS

The Company is exposed to fluctuations in commodity prices, interest rates and Canada/U.S. exchange rates. The Company, when appropriate, utilizes financial instruments to manage its exposure to these risks.

a) Commodity price risk management

The Company enters into hedge transactions on crude oil and natural gas. The agreements entered into are forward transactions providing the Company with a range of fixed prices on the commodities sold. Gains and losses with respect to these transactions have been recorded using hedge accounting. Oil and natural gas revenues for the year ended December 31, 2003 include losses of $8.0 million (2002 – $1.2 million gain; 2001 – $3.7 million gain) on these transactions.

The following table outlines financial agreements in place:

As at December 31,	Term	Daily Notional Volume	Price Collars	Unrealized Gain/(Loss)
Natural gas				
Collar	Nov. 03 – Mar. 04	9,524 mcf	$5.51/mcf - $8.93/mcf	$ 58
Collar	Jan. 04 – June 04	9,524 mcf	$5.12/mcf - $6.75/mcf	$ (311)
Collar	Jan. 04 – Mar. 04	9,524 mcf	$6.18/mcf - $8.14/mcf	$ (109)
Collar	Apr. 04 – Oct. 04	9,524 mcf	$4.99/mcf - $6.33/mcf	$ (227)
Crude oil				
Collar	Jan. 04 – Dec. 04	1,500 bbls	U.S.$25.83/bbl – U.S.$29.37/bbl	$ U.S.(1,093)

The following table outlines the financial agreements that were entered into by the Company, subsequent to December 31, 2003 and are currently outstanding:

	Term	Daily Notional Volume	Price Collars
Natural gas			
Collar	Apr. 04 – Oct. 04	9,524 mcf	$5.51/mcf - $7.43/mcf
Collar	Apr. 04 – Dec. 04	4,762 mcf	$5.25/mcf - $7.46/mcf
Collar	July 04 – Dec. 04	4,762 mcf	$6.04/mcf - $7.61/mcf

b) Interest rate risk management

Concurrent with the closing of the senior notes offering, the Company entered into interest rate swap arrangements with its banking syndicate that convert fixed rate U.S. dollar denominated interest obligations to floating rate Canadian dollar denominated interest obligations. Interest paid by the Company on the U.S. $165.0 million principal is based upon a notional amount of CDN $259.0 million times the rate determined to be the aggregate of the 90 day Bankers' Acceptance rate plus 4.85% for each settlement period.

The terms of the swaps correlate with the terms of the debt agreement and have been accounted for using hedge accounting. At December 31, 2003, there was an unrealized hedge loss, calculated on a mark-to-market basis of $8.9 million (2002 - $15.4 million gain) relating to the interest rate swap.

c) Foreign currency risk management

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and to a certain extent natural gas prices are based upon reference prices denominated in U.S. dollars, while the majority of the Company's expenses are denominated in Canadian dollars. When appropriate, the Company enters into agreements to fix the exchange rate of Canadian dollars to U.S. dollars in order to manage the risk. During the year a gain of $2.5 million was realized and included in revenue (2002 - $0.4 million, 2001 - $nil). At December 31, 2003, all swaps expired and the Company has not entered into any new arrangements.

d) Credit risk management

Accounts receivable include amounts receivable for oil and natural gas sales which are generally made to large credit worthy purchasers, and amounts receivable from joint venture partners which are recoverable from production. Accordingly, the Company views credit risks on these amounts as low.

The Company is exposed to losses in the event of non-performance by counter-parties to financial instruments. The Company deals with major institutions and believes these risks are minimal.

e) Fair value of financial assets and liabilities

The fair values of the Company's financial assets and liabilities, other than its senior term notes, that are included in the Company's consolidated balance sheet as at December 31, 2003 approximate their carrying value. The estimated fair value of senior term notes is $231.6 million as of December 31, 2003 (2002 - $271.1 million) based upon market information.

15. CASH FLOW

Changes in non-cash working capital items increased (decreased) cash as follows:

Years ended December 31,	2003	2002	2001
Accounts receivable and other	$ (16,593)	$ 1,312	$ (413)
Accounts payable	23,671	(2,285)	5,332
Taxes payable	1,541	656	127
	$ 8,619	$ (317)	$ 5,046
Operating activities			
Accounts receivable and other	$ (3,675)	$ (6,480)	$ (10,704)
Accounts payable	3,488	981	3,311
Taxes payable	1,541	656	127
	1,354	(4,843)	(7,266)
Financing activities			
Accounts receivable and other	(467)	–	–
Accounts payable	(920)	3,514	–
	(1,387)	3,514	–
Investing activities			
Accounts receivable and other	(12,451)	7,792	10,291
Accounts payable	21,103	(6,780)	2,021
	8,652	1,012	12,312
	$ 8,619	$ (317)	$ 5,046

Amounts paid during the year relating to interest expense and capital taxes are as follows:

Years ended December 31,	2003	2002	2001
Interest paid	$ 26,923	$ 15,042	$ 13,054
Capital taxes paid	$ 1,485	$ 1,084	$ 793

16. COMMITMENTS AND CONTINGENT LIABILITIES

a) Commitments

The Company has committed to certain payments under operating leases over the next three years, as follows:

As at December 31,	2004	2005	2006
Equipment	$ 1,658	$ 3,709	$ 479
Office rent	1,452	481	–
	$ 3,110	$ 4,190	$ 479

b) Legal proceedings

The Company is involved in various legal claims associated with normal operations. These claims, although unresolved at the current time, are minor in nature and are not expected to have a material impact on the financial position or results of operations of the Company.

17. SUBSEQUENT EVENT

Subsequent to the year end, the Company made an offer to acquire all the issued and outstanding shares of Redwood Energy, Ltd. ("Redwood"). On April 12, 2004 the Company acquired 87.7% of the outstanding shares and extended the offer to April 26, 2004 to secure the remainder.

The total cash consideration of Redwood is expected to be $17.7 million.

18. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

Reconciliation of consolidated financial statements to United States generally accepted accounting principles

These consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conforms to accounting principles generally accepted in the United States of America ("U.S. GAAP"). The significant differences in those principles, as they apply to the Company's statements of earnings, balance sheets and statements of cash flows, are described below.

Reconciliation of net earnings under Canadian GAAP to U.S. GAAP

For the years ended December 31,	Note	2003	2002	2001
			(restated note f)	
Net earnings for year, as reported		$ 118,880	$ 18,312	$ 55,015
Adjustments:				
Accretion of asset retirement obligations	*h*	–	1,241	1,085
Depreciation and depletion	*h*	–	542	511
Site restoration provision	*h*	–	(1,072)	(678)
Related income taxes	*h*	–	(225)	(297)
Accounting for income taxes	*d*	(743)	(5,402)	(8,715)
Other income (expense), net	*f*	(14,425)	8,659	–
Net earnings before change in accounting principle – U.S. GAAP		103,712	22,055	46,921
Cumulative effect of change in accounting principle, net	*h*	(5,681)	–	–
Net earnings – U.S. GAAP		$ 98,031	$ 22,055	$ 46,921
Net earnings per common share before change in accounting principle – U.S. GAAP				
Basic		$ 0.89	$ 0.19	$ 0.43
Diluted		$ 0.85	$ 0.19	$ 0.41
Net earnings per common share – U.S. GAAP				
Basic		$ 0.84	$ 0.19	$ 0.43
Diluted		$ 0.80	$ 0.19	$ 0.41

Comprehensive income under U.S. GAAP

For the years ended December 31,	Note	2003	2002	2001
Statement of comprehensive income	*e*			
Net earnings for the year – U.S. GAAP		$ 98,031	$ 22,055	$ 46,921
Accounting for hedging	*f*	858	(1,741)	123
Comprehensive income		$ 98,889	$ 20,314	$ 47,044

Impact of U.S. GAAP on balance sheets

As at December 31, 2003	Note	As reported	Increase (decrease)	U.S. GAAP
Assets				
Property and equipment		$ 940,057	$ –	$ 940,057
Deferred financing charges	*g*	11,432	(3,423)	8,009
Liabilities				
Asset retirement obligations	*h*	$ 17,329	$ –	$ 17,329
Accounting for derivatives	*f*	–	10,895	10,895
Future income taxes	*f*	223,807	(4,246)	219,561
Senior term notes	*g*	213,246	(3,423)	209,823
Shareholders' equity				
Capital stock	*d*	$ 131,577	$ 29,987	$ 161,564
Retained earnings		224,569	(36,636)	187,933

As at December 31, 2002	Note	As reported	Increase (decrease)	U.S. GAAP
				(restated note f)
Assets				
Property and equipment		$ 715,001	$ (8,832)	$ 706,169
Accounting for hedging	*f*	–	15,402	15,402
Deferred financing charges	*g*	13,444	(4,060)	9,384
Liabilities				
Asset retirement obligations	*h*	$ 17,335	$ (17,335)	$ –
Accounting for hedging	*f*	–	3,446	3,446
Future income taxes	*f, h*	202,371	7,860	210,231
Senior term notes	*g*	260,634	(4,060)	256,574
Shareholders' equity				
Capital stock	*d*	$ 128,079	$ 29,244	$ 157,323
Retained earnings		112,039	(16,645)	95,394

Impact of U.S. GAAP on statements of cash flow

The application of U.S. GAAP would not change the amounts as reported under Canadian GAAP for cash flows provided by (used in) operating, investing or financing activities, except for the following:

i) Unspent flow-through share proceeds which have been received at year-end. During 2003, the Company received $4.2 million in proceeds from the issuance of flow-through shares of which $4.2 million remained unspent as at December 31, 2003 (2002 - $17.6 million, 2001 - $25.6 million). Accordingly, under U.S. GAAP, these proceeds would be disclosed separately on the balance sheet as restricted cash and would not be treated as cash or cash equivalents for statement of cash flow reporting purposes. The result of this difference would be to disclose a decrease in restricted cash as an investing activity and to reduce cash, end of year by $4.2 million (2002 - $17.6 million, 2001 – $25.6 million);

ii) The consolidated statements of cash flow include, under investing activities, changes in working capital for items not affecting cash, such as accounts payable and accounts receivable, related to the non-cash elements of property and equipment additions. This disclosure is provided in order to disclose the aggregate costs related to such activities and to identify the non-cash component thereof and to arrive at the cash amounts. This presentation is not permitted under U.S. GAAP; and

iii) The consolidated statements of cash flow, for the year ended December 31, 2003 would have disclosed an ending cash balance of $11.4 million after reflecting the adjustment for restricted cash relating to U.S. GAAP treatment of unspent flow-through share proceeds (2002 - $2.9 million, 2001 - $20.4 million). Under U.S. GAAP, the negative, comparative ending cash balances (or bank overdrafts) would be reflected as a financing activity in the consolidated statements of cash flow.

Impact of U.S. GAAP on notes to the consolidated financial statements

a) Full cost accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian and U.S. GAAP differ in the following respects. Under U.S. GAAP, an impairment test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10%, of the estimated constant dollar, future net operating revenue from proved reserves plus unimpaired unproved property costs and applicable taxes. Under Canadian GAAP, a similar impairment test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize escalated pricing to determine whether impairments exist. If an impairment exists, then the amount of the write down is determined using the fair value of reserves. The Company has completed a impairment test calculation at December 31, 2003 and for all prior years, with no write-downs required under either Canadian or U.S. GAAP.

b) Stock-based compensation

Under Canadian GAAP, compensation costs have been recognized in the consolidated financial statements for stock options granted to employees and directors in 2003. For the effect on periods prior to 2003 of stock-based compensation on the Canadian GAAP financials, which would be the same adjustment under U.S. GAAP, see Note 10.

c) Future income taxes

Under U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates. The future income tax adjustments included in the reconciliation of net earnings under Canadian GAAP to U.S. GAAP and the balance sheet effects include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The net future income tax liability is comprised of:

As at December 31,	2003	2002
Future income tax liabilities		
Property and equipment	$ 169,855	$ 179,739
Timing of partnership items	62,975	34,494
Future income tax assets		
Attributed Canadian royalty income	(9,667)	(5,175)
Asset retirement obligations	(6,024)	(709)
Non-capital losses carried forward	(789)	(1,360)
Other	3,211	3,242
Future income taxes	$ 219,561	$ 210,231

d) Flow through shares

U.S. GAAP requires that flow-through shares be recorded at their fair value without any adjustment for the renouncement of the tax deductions and any temporary difference resulting from the renouncement must be recognized in the determination of tax expense in the year incurred.

The impact of recording flow-through shares at their fair value for the year ended December 31, 2003, was to increase the future income tax provision by $0.7 million (2002 - $5.4 million; 2001 - $8.7 million) and to increase capital stock by a corresponding amount.

e) Comprehensive income

Statement of Financial Accounting Standards 130, "Comprehensive Income", requires the reporting of comprehensive income in addition to net earnings. Comprehensive income includes net income plus other comprehensive income. Management believes that it has no other comprehensive income other than as described under Note 18(f).

f) Derivative instruments and hedging

The Company uses forward contracts and options on forward contracts to manage the risk of fluctuations in the market price of natural gas, crude oil and the change in interest rates. For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards ("SFAS") 133 effective January 1, 2001. SFAS 133 requires that all derivatives be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings unless specific hedge accounting criteria are met.

At December 31, 2003, the natural gas and crude oil futures contracts are accounted for as cash flow hedges. These contracts are recorded at fair value on the balance sheet as a $2.0 million liability at December 31, 2003 (2002 - $3.4 million). The effective portion of the change in fair value is recorded in comprehensive income, net of tax. The ineffective portion of the change in fair value is recorded in net earnings, net of tax. The effective portion of these commodity contracts is a $0.9 million gain, which is recorded in comprehensive income as at December 31, 2003 (2002 - $1.7 million loss; 2001 - $123 thousand gain). The ineffective portion of these commodity contracts is $nil which is recorded in net earnings as at December 31, 2003 (2002 - $253 thousand loss; 2001 - $nil).

During 2003, it was determined that the interest rate swap arrangements relating to the Company's senior term notes, Note 7, do not qualify for hedge accounting in accordance with SFAS 133 and should be accounted for on a mark-to-market basis. Accordingly, 2002 comparative amounts have been restated to reflect the appropriate accounting treatment. As a result, the change in the fair value of the interest rate swap arrangements of $15.4 million, previously recorded as an increase to the senior term notes, was charged to income, net of the future income taxes of $6.5 million, with a corresponding increase in net earnings and retained earnings of $8.9 million. Basic earnings per share and diluted earnings per share for the year ended December 31, 2002, increased $0.07 and $0.08 per share respectively as a result of the restatement.

At December 31, 2003, the Company recorded a liability of $8.9 million and a $14.4 million loss after future income taxes, with respect to the interest rate swap arrangements on a mark-to-market basis.

g) Deferred financing charges

Under U.S. GAAP, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred financing charges. At December 31, 2003 deferred financing charges and senior term notes were reduced by $3.4 million (2002 - $4.1 million).

h) Asset retirement obligations

The Company early adopted the Canadian Accounting Standard for asset retirement obligations, as outlined in the CICA handbook, section 3110. This standard is equivalent to U.S. SFAS 143, "Accounting for Asset Retirement Obligations", which was effective for fiscal periods beginning on or after January 1, 2003. Early adopting the Canadian standard eliminated a U.S. GAAP reconciling item in respect to accounting for the obligations. However, a difference is created in how the transition amounts are disclosed. U.S. GAAP requires the cumulative impact of a change in an accounting principle be presented in the current year consolidated statement of earnings and prior periods not be restated. Consequently, prior year comparative periods, under U.S. GAAP, have been revised to eliminate the prior period restatement made under Canadian GAAP.

i) Receivable and payable amounts

As at December 31,		2003		2002
(in thousands of Canadian dollars)				
Accounts receivable and other includes the following:				
Revenue receivable	$	63,687	$	58,518
Joint interest receivable		21,685		11,196
Other receivables		11,911		10,975
	$	97,283	$	80,689

As at December 31,		2003		2002
(in thousands of Canadian dollars)				
Accounts payable and accrued liabilities includes the following:				
Trade payables	$	67,753	$	45,387
Royalties payable		10,920		8,209
Other payables		7,057		8,463
	$	85,730	$	62,059

j) Recent accounting pronouncements

During 2003, the following new standard was issued:

ACCOUNTING FOR CERTAIN FINANCIAL INSTRUMENTS

In May 2003, the FASB issued Statement of Accounting Standards No. 150 "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" which changes the accounting for mandatorily redeemable shares, put options, forward purchase contracts and obligations that can be settled with shares effective for financial instruments entered into or modified after May 31, 2003. As the Company does not have any of these types of instruments outstanding, the adoption of this statement did not have any impact upon the Company's consolidated financial statements.

SUPPLEMENTAL OIL AND NATURAL GAS INFORMATION (UNAUDITED)

A) Net Proved Oil and Natural Gas Reserves

The net proved oil and natural gas reserve estimates as at December 31, 2003, 2002 and 2001 set forth below were prepared in accordance with guidelines established by the Securities and Exchange Commission and accordingly were based on existing economic and operating conditions. Oil and natural gas prices in effect as of the respective year ends were used without any escalation except in those instances where the sale is covered by contract, in which case the applicable contract price is used. Operating costs, royalties and future development costs were based on current costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present value should not be construed as the current market value of the Company's oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. All of the reserves are located in Canada.

ESTIMATED QUANTITIES OF RESERVES

	2003		2002		2001	
Years ended December 31,	Crude oil & NGL's (mbbls)	Natural Gas (mmcf)	Crude oil & NGL's (mbbls)	Natural Gas (mmcf)	Crude oil & NGL's (mbbls)	Natural Gas (mmcf)
Balance, beginning of year	10,723	314,501	9,777	262,448	9,423	223,761
Revisions of previous estimates	674	(12,821)	529	11,712	313	(3,186)
Extensions, discoveries and other additions	2,869	54,128	1,829	58,853	1,611	63,248
Acquisitions of minerals in place	404	2,333	514	18,805	301	7,412
Dispositions of minerals in place	–	–	(84)	(5,343)	(45)	(382)
Production	(1,751)	(31,568)	(1,842)	(31,974)	(1,826)	(28,405)
Balance, end of year	12,919	326,573	10,723	314,501	9,777	262,448
Proved developed reserves						
Balance, beginning of year	9,723	293,836	8,938	232,319	8,576	187,969
Balance, end of year	10,309	288,899	9,723	293,836	8,938	232,319

B) Capitalized Costs Related to Oil and Natural Gas Activities

The aggregate capitalized costs of oil and natural gas activities and costs incurred in oil and natural gas property acquisitions, development and exploration activities are as follows (excluding MPP):

CAPITALIZED COSTS

As at December 31,	2003	2002
(in thousands of Canadian dollars)		
Proved properties	$ 951,541	$ 737,535
Unproved properties		
Acquisition	103,977	101,044
Exploration	57,877	54,205
Accumulated depletion and depreciation	(238,413)	(177,783)
	$ 874,982	$ 715,001

COSTS INCURRED ON UNPROVED PROPERTIES

As at December 31,	Cumm. 2003	Includes costs incurred in 2003	2002	2001	Prior Years
(in thousands of Canadian dollars)					
Acquisition	$ 103,977	$ 2,933	$ (9,720)	$ 38,455	$ 72,309
Exploration	57,877	3,672	4,000	23,759	26,446
	$ 161,854	$ 6,605	$ (5,720)	$ 62,214	$ 98,755

COSTS INCURRED

December 31,	2003	2002	2001
(in thousands of Canadian dollars)			
Acquisition costs (net of disposition)			
Proved properties	$ 11,224	$ 27,157	$ 30,716
Unproved properties	2,933	(9,720)	38,455
Development costs			
Development of proved undeveloped reserves	25,232	21,280	16,088
Other	115,612	52,971	27,229
Exploration costs	64,615	63,462	75,417
Total costs incurred	$ 219,616	$ 155,150	$ 187,905

Costs are transferred into the depletion base on an ongoing basis as the undeveloped properties are evaluated and proved reserves are established or impairment determined. Pending determination of proved reserves attributable to the above costs, the Company cannot assess the future impact on the amortization rate.

C) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The standardized measure of discounted future net cash flows and changes therein relating to proved oil and natural gas reserves ("Standardized Measure") does not purport to present the fair market value of the Company's oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revisions. The computation also excludes values attributable to the Company's midstream interests, referred to in the Financial Statements as MPP.

Under the Standardized Measure, future cash inflows were estimated by applying year end prices, adjusted for contracts currently in place to deliver production to the estimated future production of year end proved reserves. Future cash inflows were reduced by estimated future production and development costs based on year end costs to determine pre-tax cash inflows. Future taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carry forwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

Years ended December 31,	2003	2002	2001
(in thousands of Canadian dollars)			
Future cash inflows	$ 2,467,604	$ 2,460,747	$ 1,270,787
Future production costs	(785,187)	(507,576)	(431,127)
Future development costs	(76,708)	(56,209)	(41,943)
Future net cash flows	1,605,709	1,896,962	797,717
Income taxes	(460,291)	(733,434)	(264,960)
Total undiscounted future net cash flows	1,145,418	1,163,528	532,757
10% annual discount for estimated timing of cash inflows	(592,409)	(509,831)	(215,296)
Standardized measure of discounted future net cash flows	$ 553,009	$ 653,697	$ 317,461

(1) The Company estimates that it will incur $17.3 million in 2004, $16.0 million in 2005 and $7.6 million in 2006 to develop proved undeveloped reserves.

The following table sets forth an analysis of changes in the standardized measure of discounted future net cash flows from proved oil and natural gas reserves:

Years ended December 31,	2003	2002	2001
(in thousands of Canadian dollars)			
Beginning of year	$ 653,697	$ 317,461	$ 709,869
Sales of production, net of production costs	(197,323)	(126,745)	(151,724)
Net change in sales prices, net of production costs	(64,509)	502,652	(807,804)
Extensions, discoveries and additions	144,565	198,811	127,656
Changes in estimated future development costs	(39,965)	(58,187)	(48,528)
Development costs incurred during the period which reduced future development costs	85,586	66,881	58,982
Revisions in quantity estimates	(69,386)	70,721	(2,099)
Accretion of discount	101,612	42,348	111,245
Purchase of reserves	6,328	55,129	17,976
Sales of reserves	–	(20,051)	(1,517)
Net change in income tax	156,350	(234,813)	389,962
Changes in production rates (timing) and other	(223,946)	(160,510)	(86,557)
Standardized measure, end of year	$ 553,009	$ 653,697	$ 317,461

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